



US008016032B2

(12) **United States Patent**  
**Mandrell et al.**

(10) **Patent No.:** **US 8,016,032 B2**  
(45) **Date of Patent:** **Sep. 13, 2011**

(54) **WELL TREATMENT DEVICE, METHOD AND SYSTEM**

(75) Inventors: **Phillip Mandrell**, Trinidad, CO (US);  
**Dustin Howard**, Trinidad, CO (US);  
**Marty Stromquist**, Denver, CO (US)

(73) Assignee: **Pioneer Natural Resources USA Inc.**

(\*) Notice: Subject to any disclaimer, the term of this patent is extended or adjusted under 35 U.S.C. 154(b) by 320 days.

(21) Appl. No.: **12/067,434**

(22) PCT Filed: **Sep. 19, 2006**

(86) PCT No.: **PCT/US2006/036503**  
§ 371 (c)(1),  
(2), (4) Date: **Sep. 5, 2008**

(87) PCT Pub. No.: **WO2007/035745**  
PCT Pub. Date: **Mar. 29, 2007**

(65) **Prior Publication Data**  
US 2008/0314600 A1 Dec. 25, 2008

**Related U.S. Application Data**

(60) Provisional application No. 60/718,481, filed on Sep. 19, 2005, provisional application No. 60/728,182, filed on Oct. 19, 2005.

(51) **Int. Cl.**  
**E21B 43/26** (2006.01)  
**E21B 47/01** (2006.01)

(52) **U.S. Cl.** ..... **166/177.5**; 166/250.17; 166/308.1;  
166/386; 166/387

(58) **Field of Classification Search** ..... 166/250.17,  
166/279, 278, 305.1, 308.1, 177.5, 386, 387  
See application file for complete search history.

(56) **References Cited**

U.S. PATENT DOCUMENTS

2,847,073 A 8/1958 Arterbury  
3,169,579 A 2/1965 Haines  
4,590,995 A 5/1986 Evans

(Continued)

FOREIGN PATENT DOCUMENTS

EP 1094195 A 9/2000

(Continued)

OTHER PUBLICATIONS

Notification Concerning Transmittal of International Preliminary Report on Patentability and Written Opinion of the International Searching Authority, Apr. 3, 2008, based on PCT/US2006/036503 filed Sep. 19, 2006, Form PCT/IB/373 and Form PCT/ISA/237, 16 pages.

(Continued)

*Primary Examiner* — Jennifer H Gay

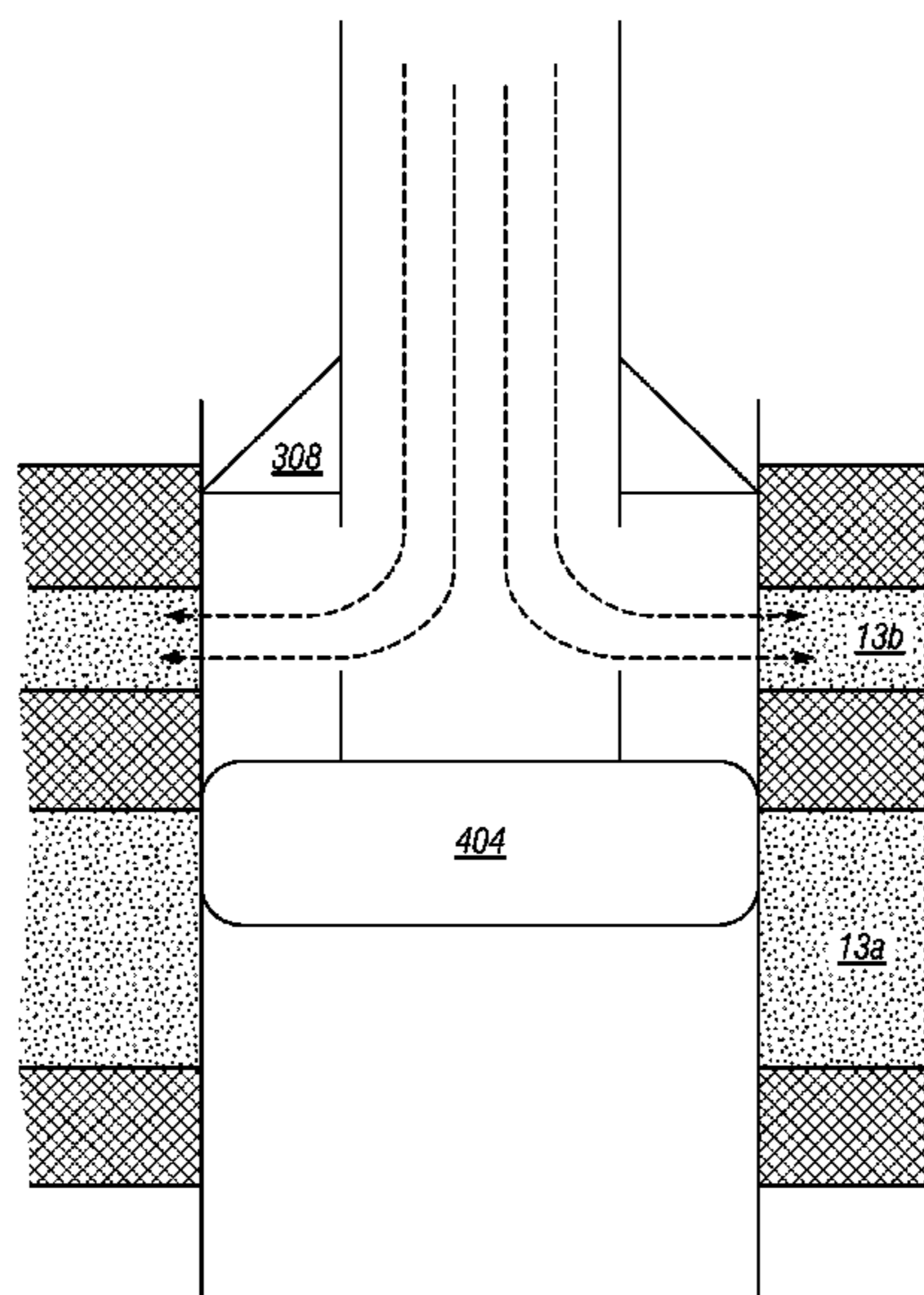
*Assistant Examiner* — Brad Harcourt

(74) *Attorney, Agent, or Firm* — Arnold & Knobloch, L.L.P.;  
Charles Knobloch; Gordon Arnold

(57) **ABSTRACT**

System, devices, and methods are described relating to the treatment (e.g., perforating, fracturing, foam stimulation, acid treatment, cement treatment, etc.) of well-bores (e.g., cased oil and/or gas wells). In at least one example, a method is provided for treatment of a region in a well, the method comprising: positioning, in a well-bore, a packer above the region of the well-bore, fixing, below the region, an expansion packer, treating the region, the treatment fixing the packer, moving the expansion packer, and moving the packer after the moving of the expansion packer.

**13 Claims, 18 Drawing Sheets**



**U.S. PATENT DOCUMENTS**

4,696,344 A 9/1987 Scott et al.  
 4,964,460 A 10/1990 Armell et al.  
 5,343,956 A \* 9/1994 Coronado ..... 166/387  
 5,456,322 A 10/1995 Tucker et al.  
 6,131,663 A 10/2000 Henley et al.  
 6,325,146 B1 12/2001 Ringgenberg et al.  
 6,328,103 B1 12/2001 Pahmiyer et al.  
 6,394,184 B2 5/2002 Tolman et al.  
 6,446,719 B2 9/2002 Ringgenbeg et al.  
 6,446,720 B1 9/2002 Ringgenberg et al.  
 6,474,419 B2 11/2002 Maier et al.  
 6,520,255 B2 2/2003 Tolman et al.  
 6,527,052 B2 3/2003 Ringgenberg et al.  
 6,533,037 B2 3/2003 Eslinger et al.  
 6,543,538 B2 4/2003 Tolman et al.  
 6,575,247 B2 6/2003 Tolman et al.  
 6,655,461 B2 12/2003 Eslinger et al.  
 6,672,405 B2 1/2004 Tolman et al.  
 6,695,057 B2 2/2004 Ingram et al.  
 6,722,437 B2 4/2004 Vercaemer et al.  
 6,729,398 B2 5/2004 Ringgenberg et al.

6,776,239 B2 8/2004 Eslinger et al.  
 6,860,326 B2 3/2005 Kilgore et al.  
 6,880,637 B2 \* 4/2005 Myers, Jr. et al.  
 6,926,088 B2 \* 8/2005 Tinker  
 6,957,701 B2 10/2005 Tolman et al.  
 7,059,407 B2 \* 6/2006 Tolman et al. .... 166/281  
 2004/0050546 A1 \* 3/2004 Tinker

**FOREIGN PATENT DOCUMENTS**

EP 1076156 A2 2/2001  
 GB 2384257 A 2/2002  
 WO WO 98/50672 A1 11/1998  
 WO 0206629 A1 1/2002

**OTHER PUBLICATIONS**

Notification of Transmittal of the International Search Report and the Written Opinion of the International Searching Authority, or the Declaration, Apr. 3, 2007, based on PCT/US2006/036503 filed Sep. 19, 2006, Form PCT/ISA/210 and Form PCT/ISA/237, 22 pages.

\* cited by examiner

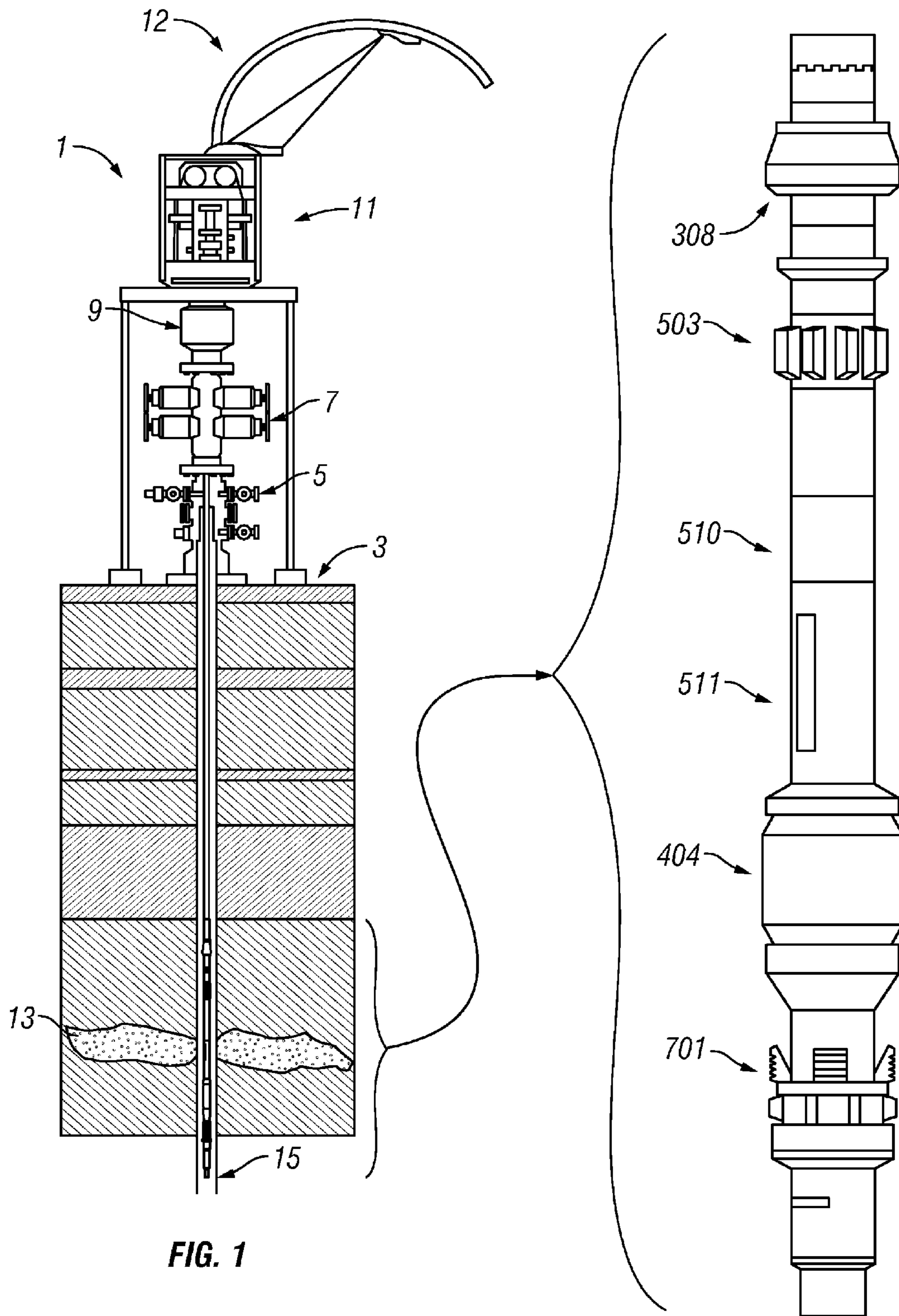


FIG. 1

FIG. 1A

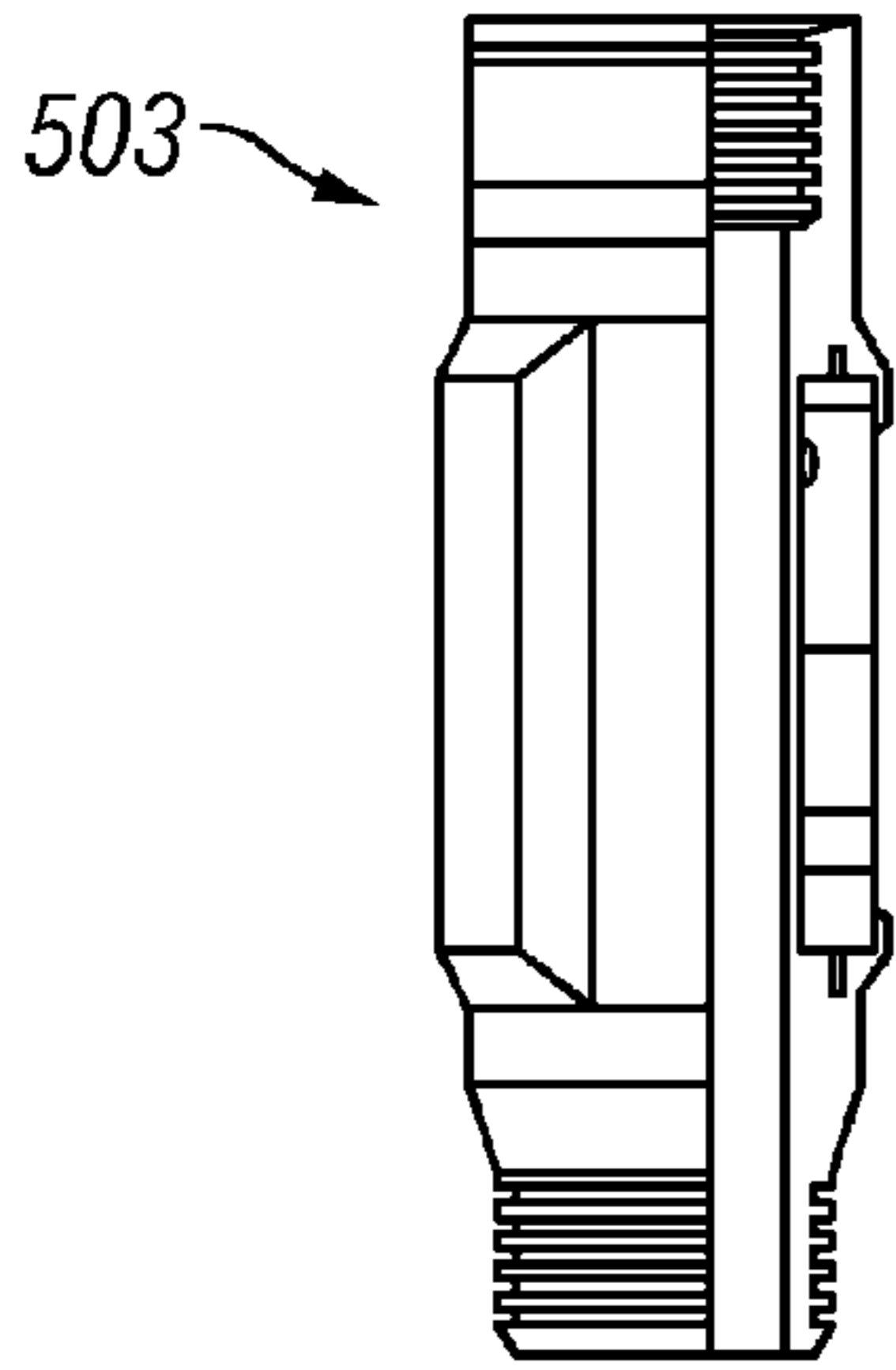


FIG. 2B

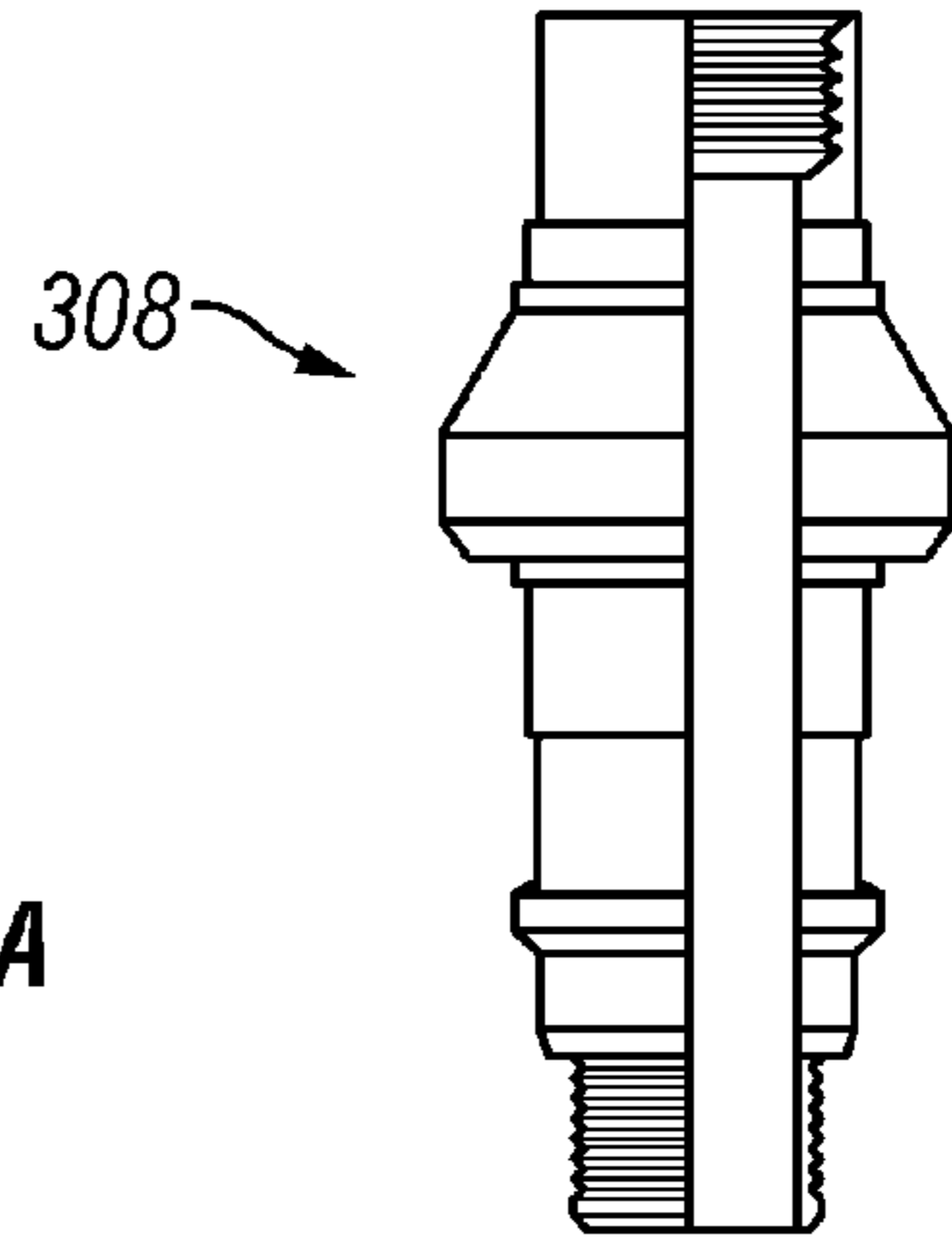


FIG. 2A

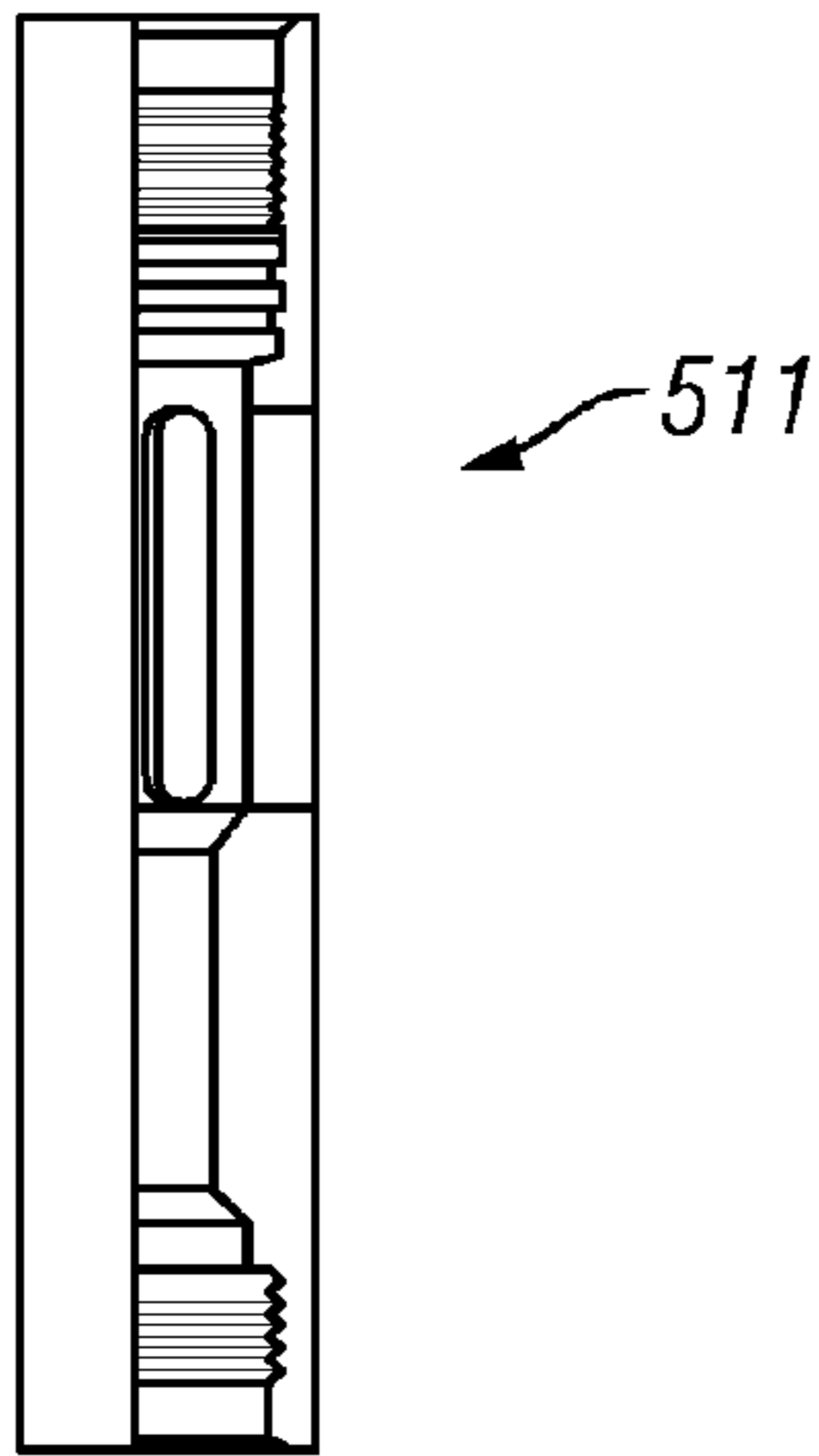


FIG. 2D

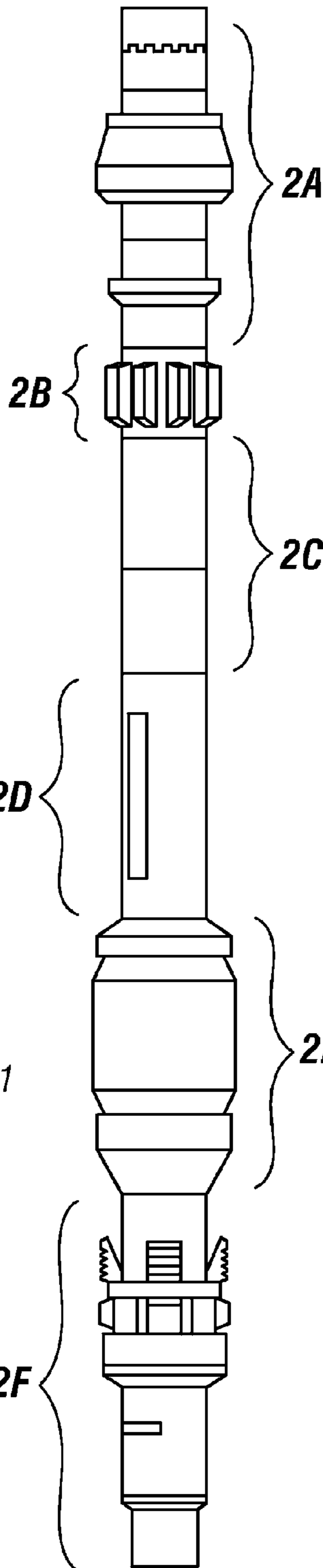


FIG. 2

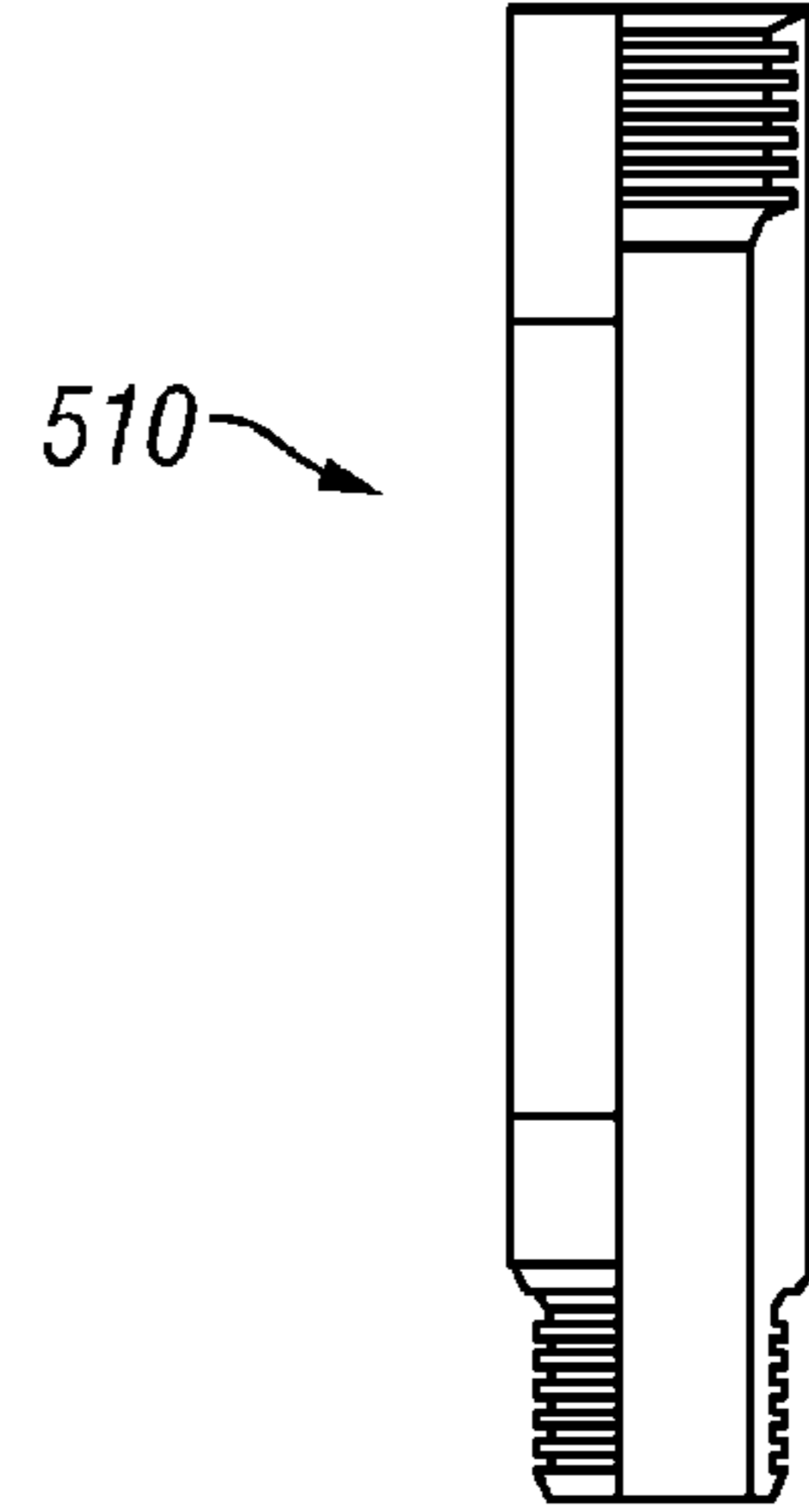


FIG. 2C

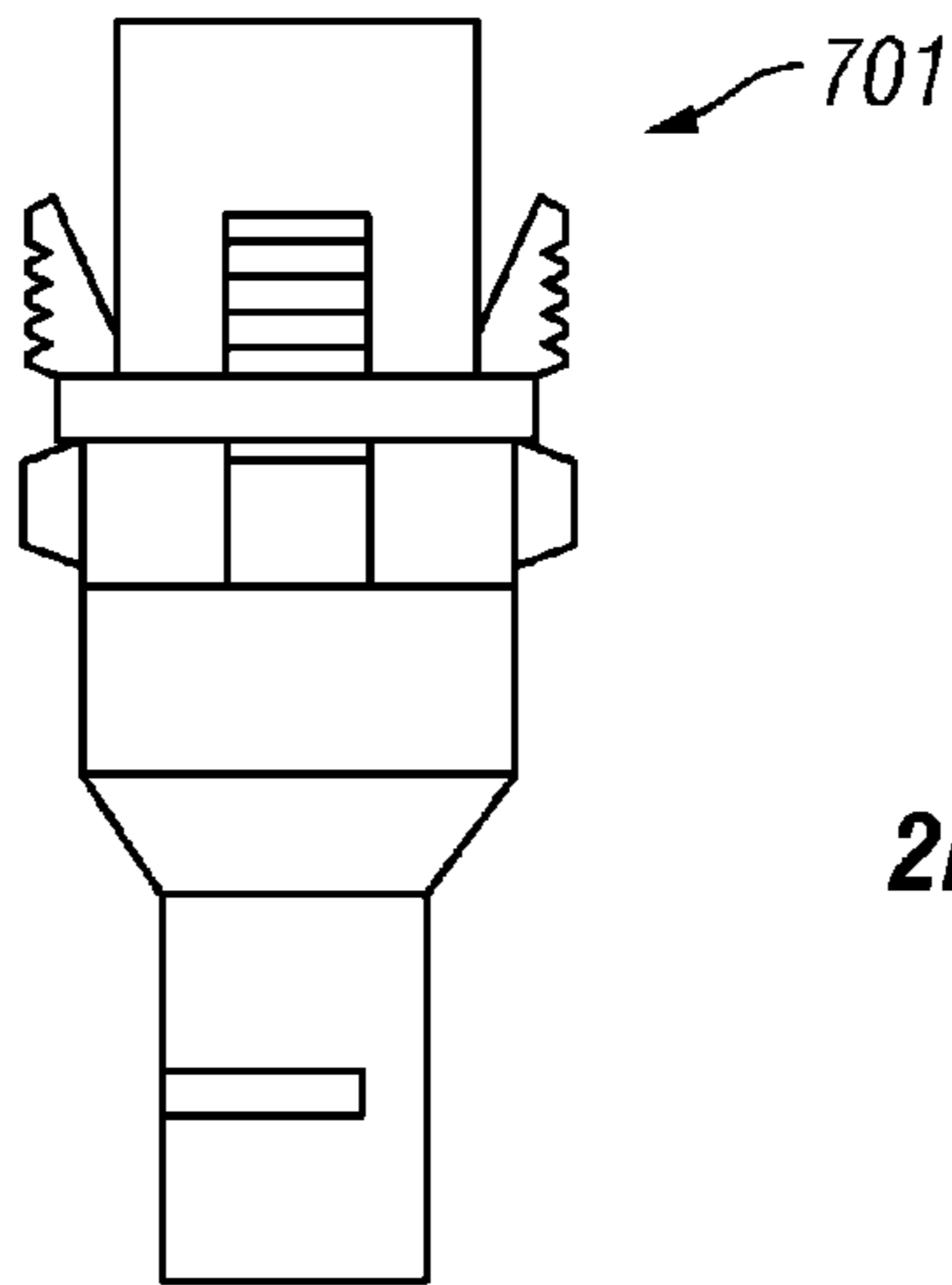


FIG. 2F

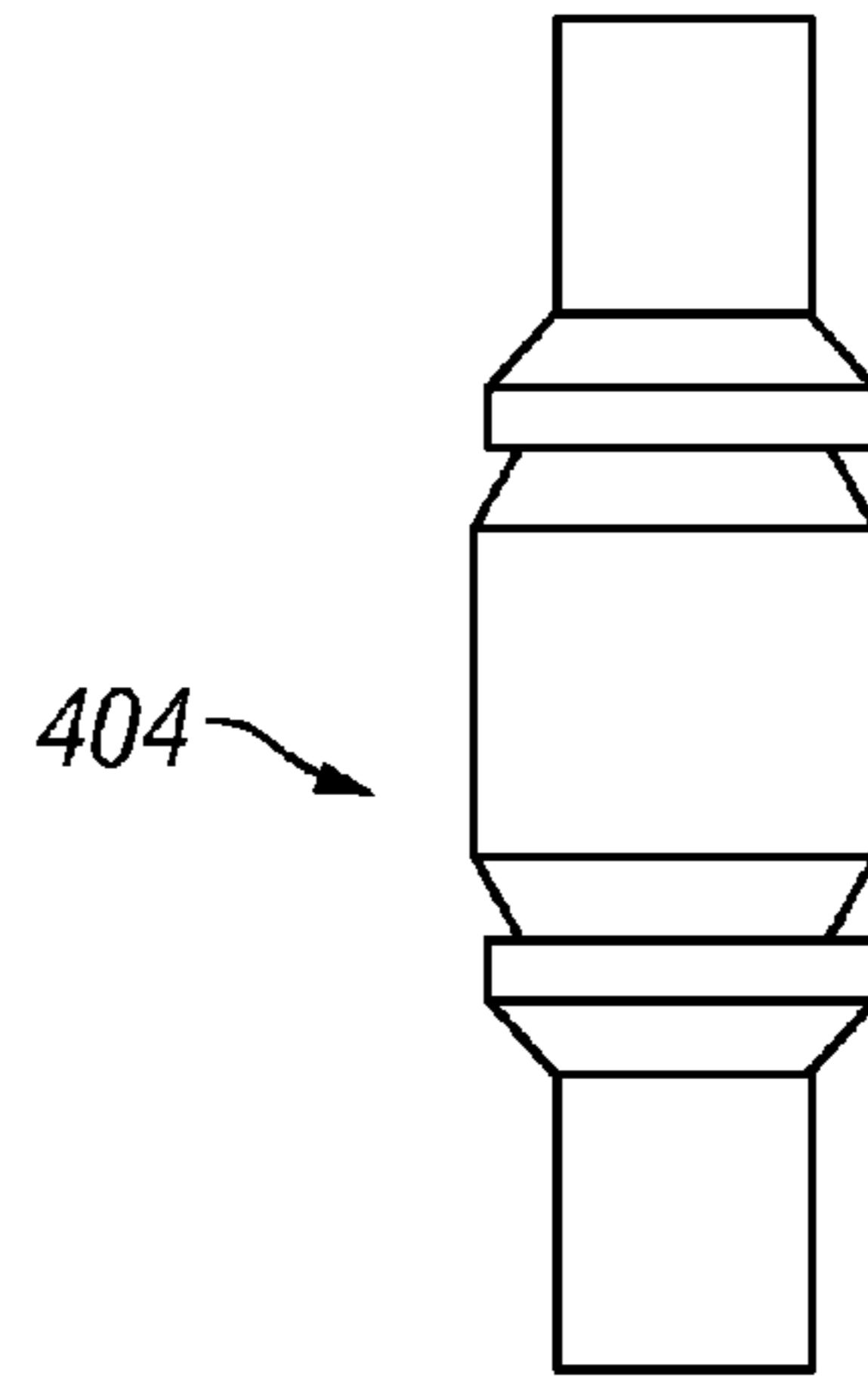


FIG. 2E

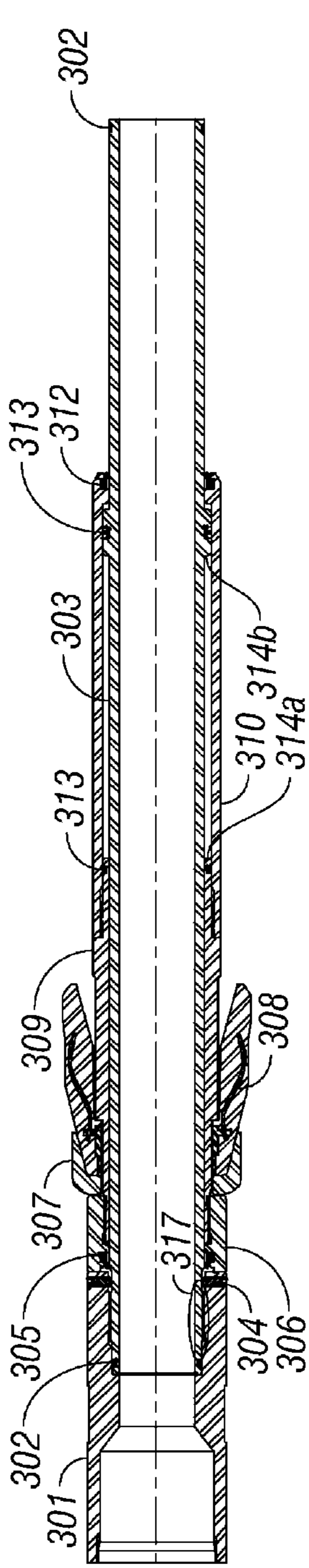


FIG. 3

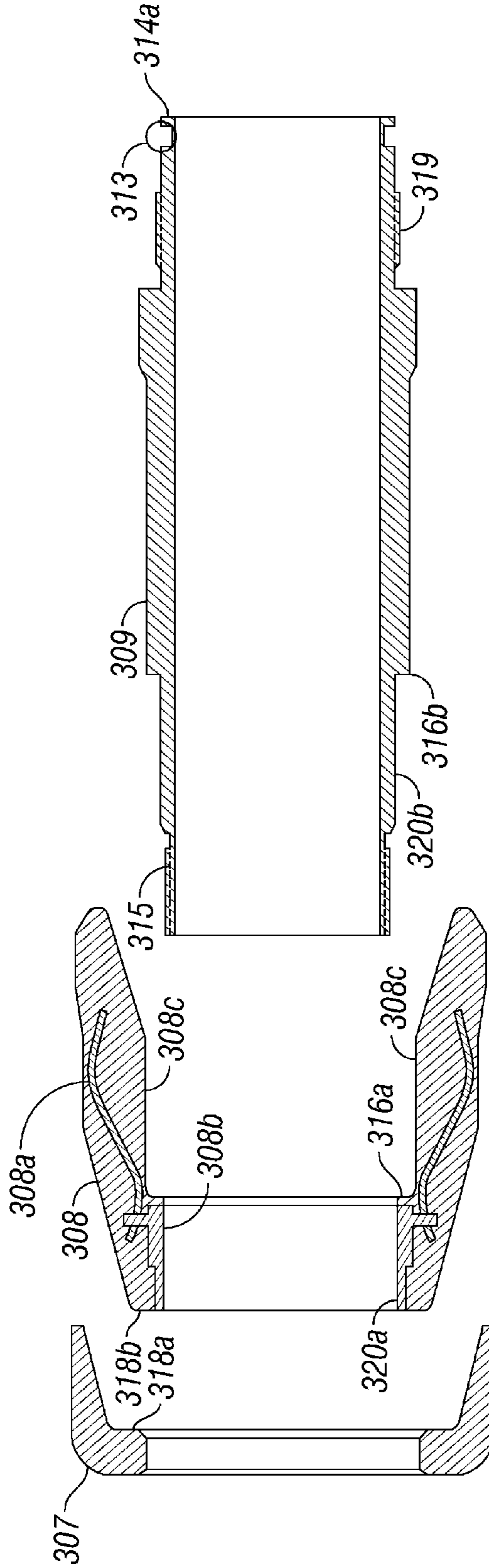


FIG. 3A

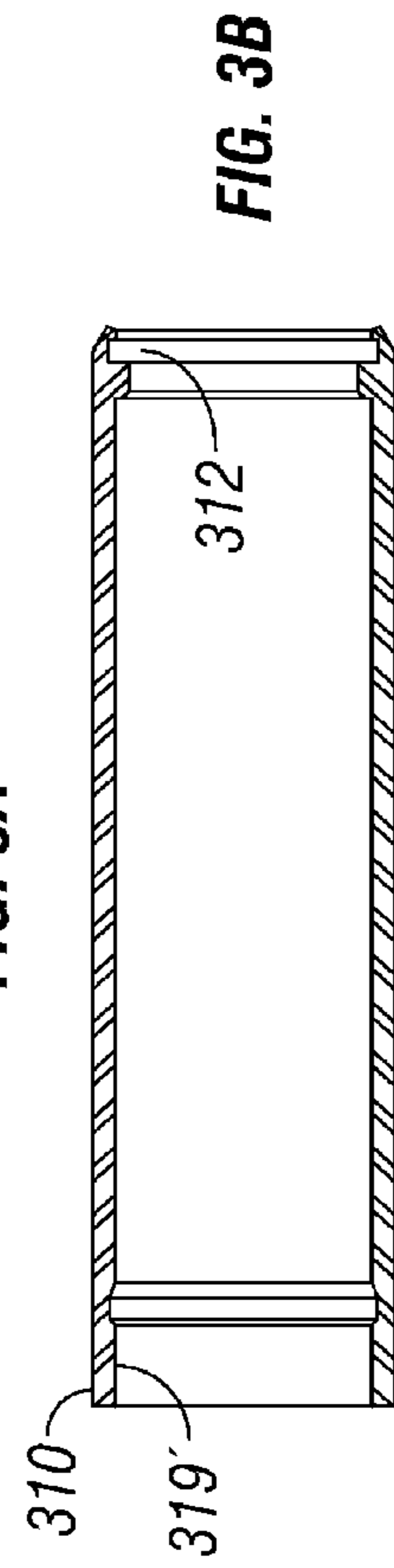


FIG. 3B

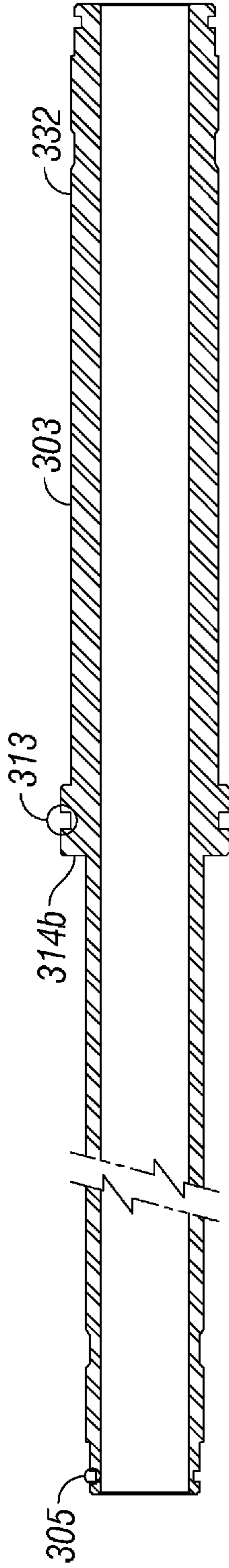


FIG. 3C

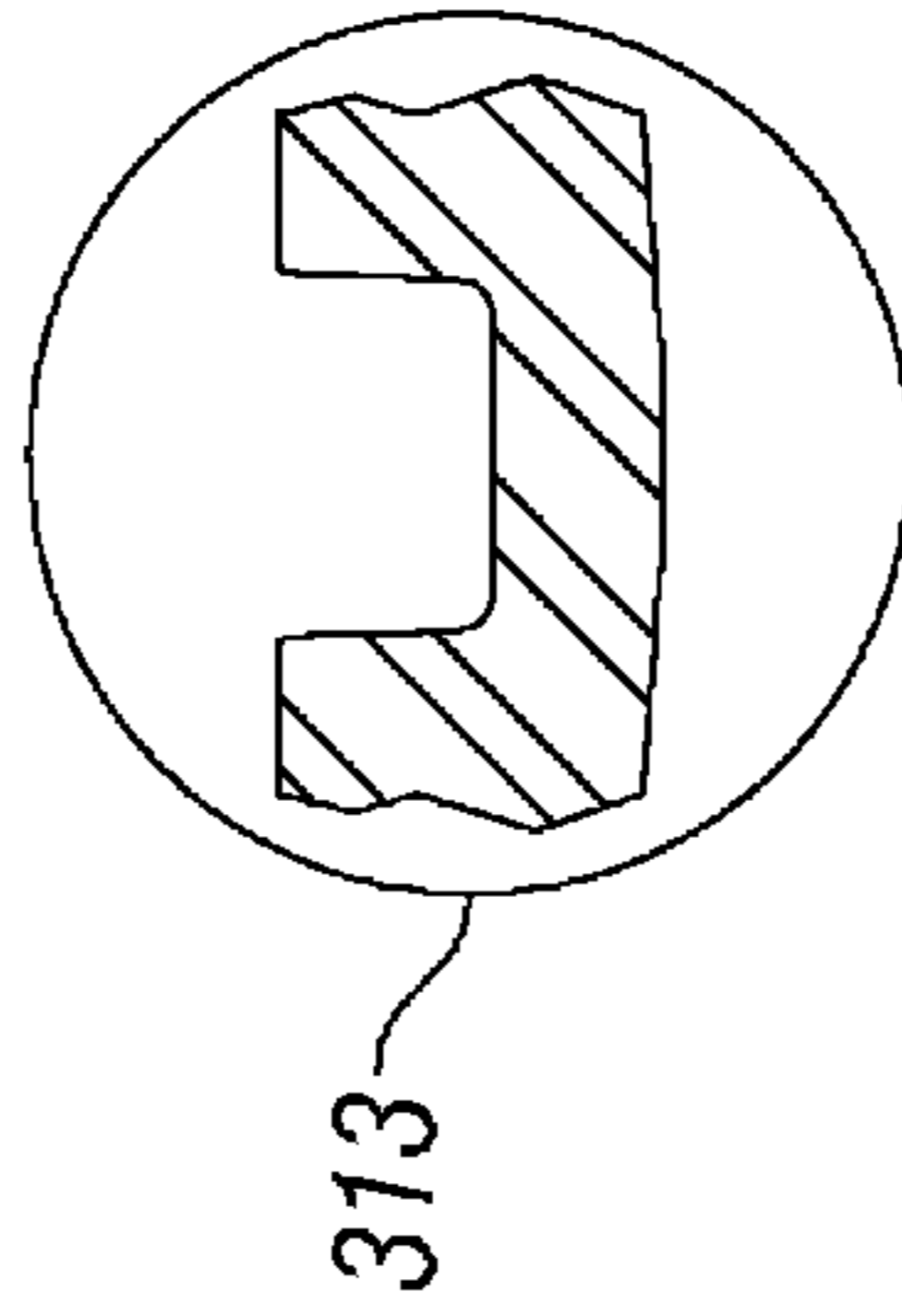


FIG. 3D

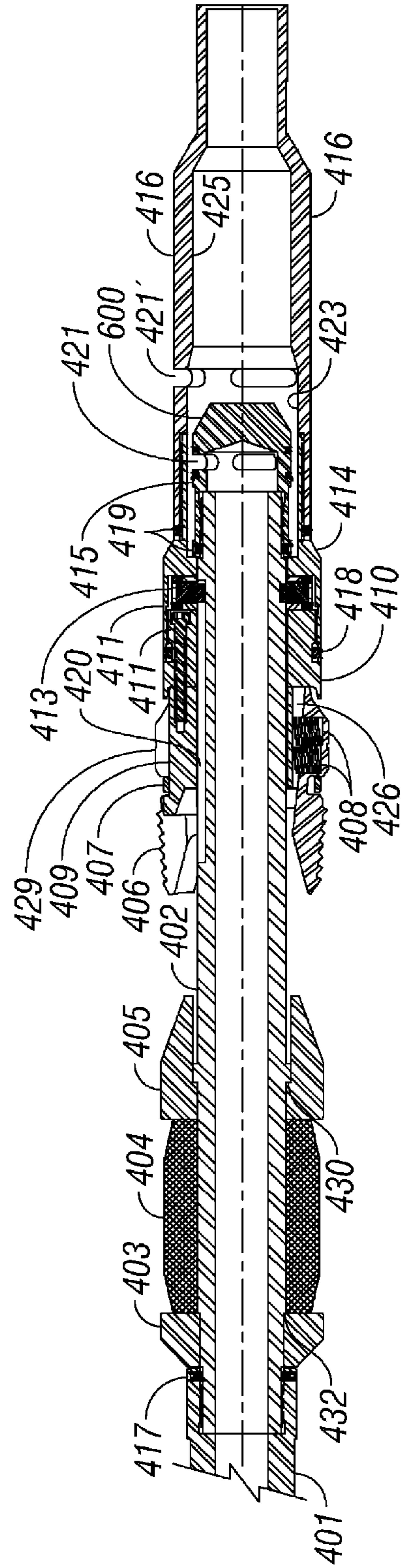


FIG. 4

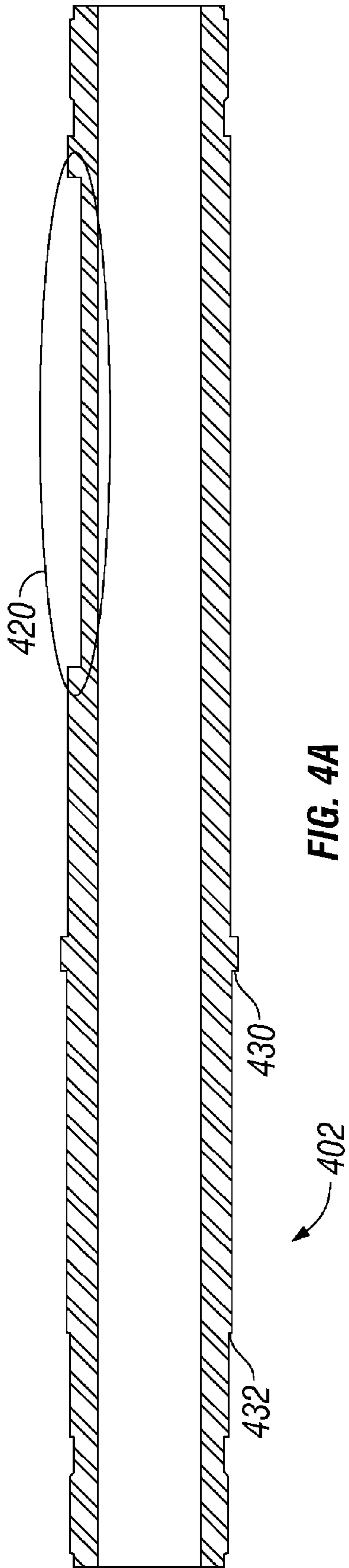


FIG. 4A

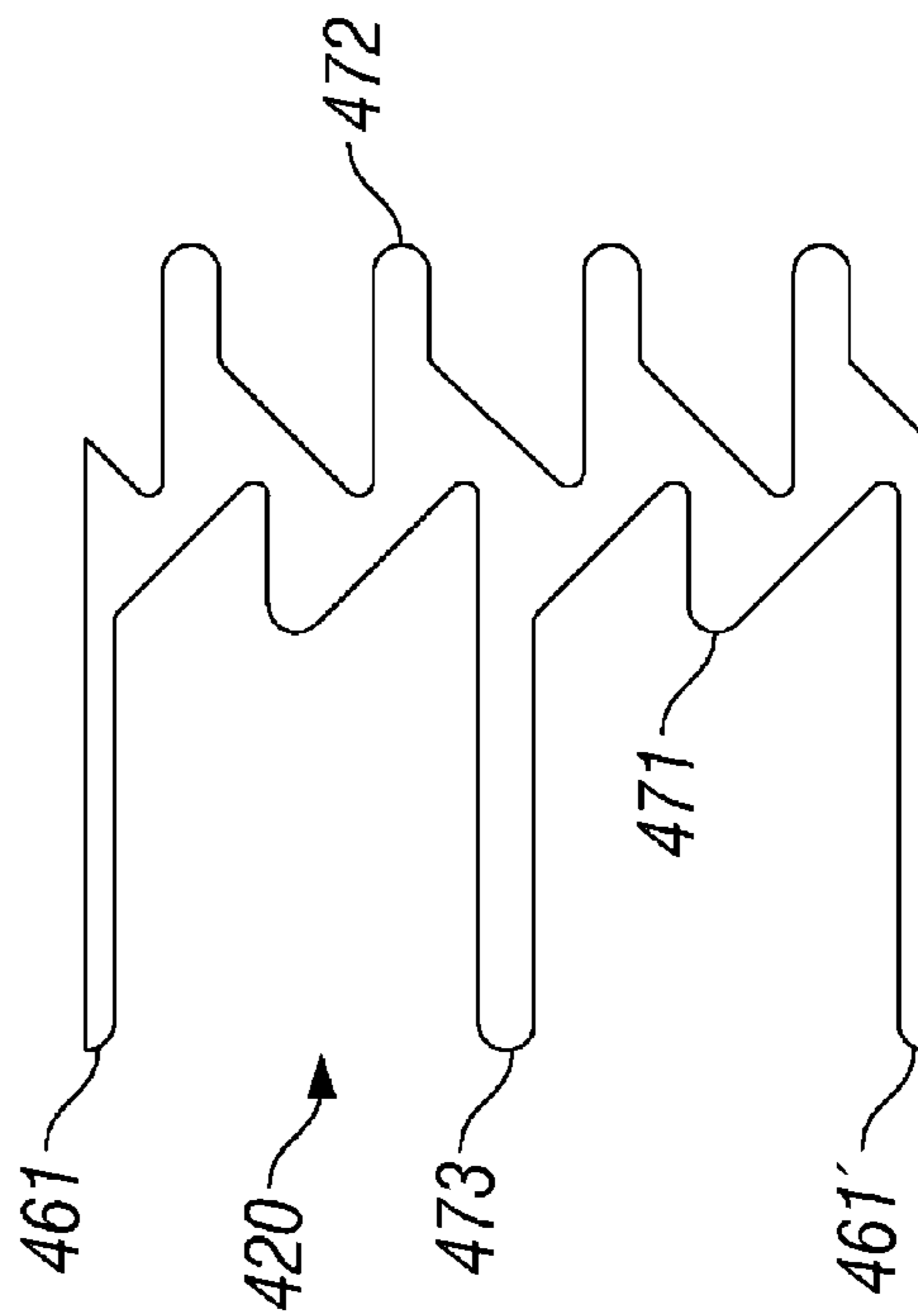
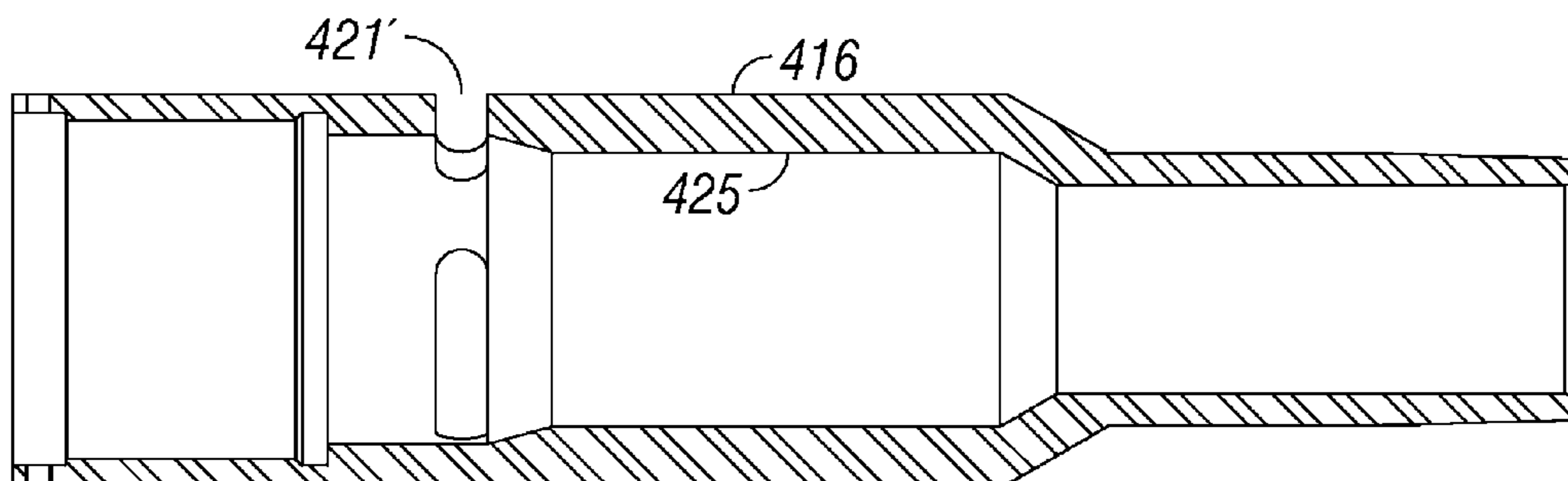
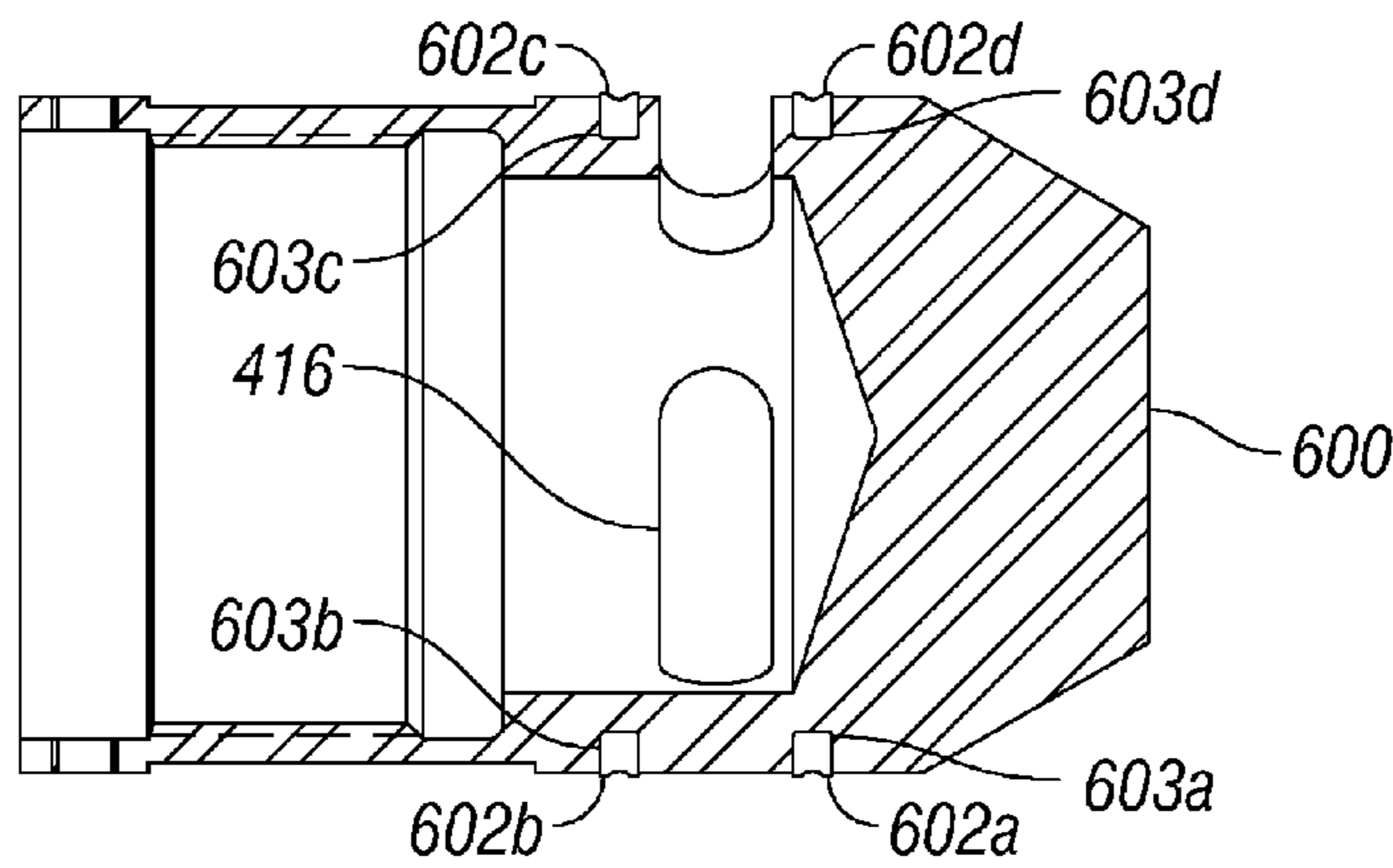
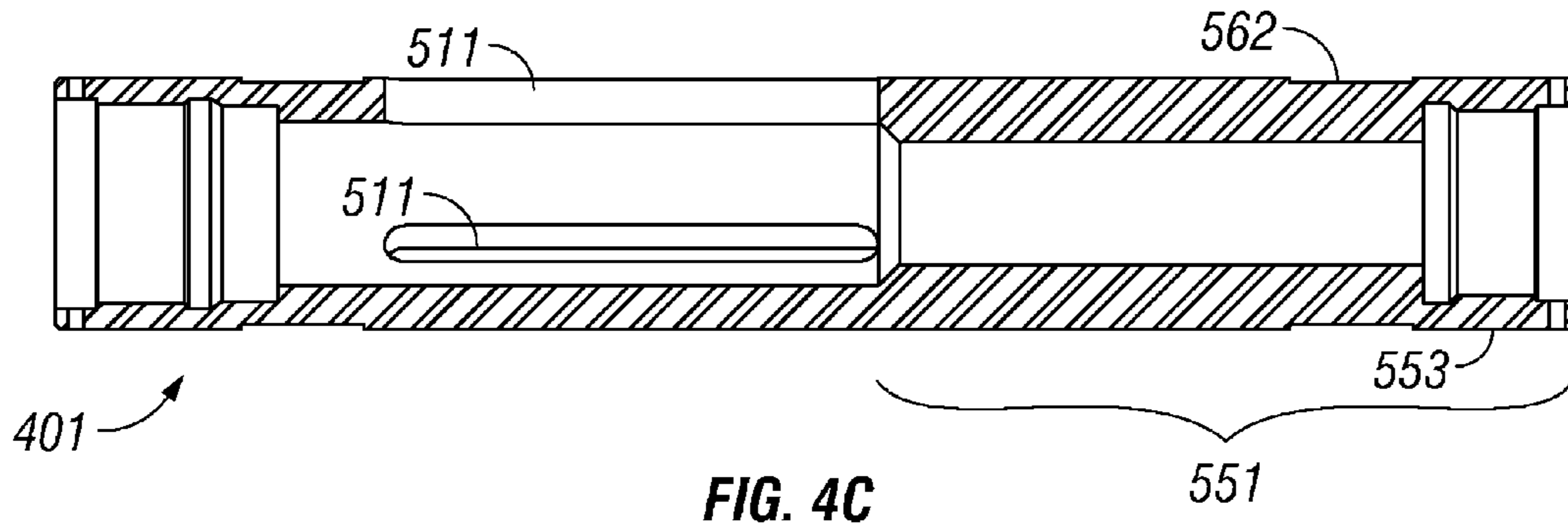


FIG. 4B





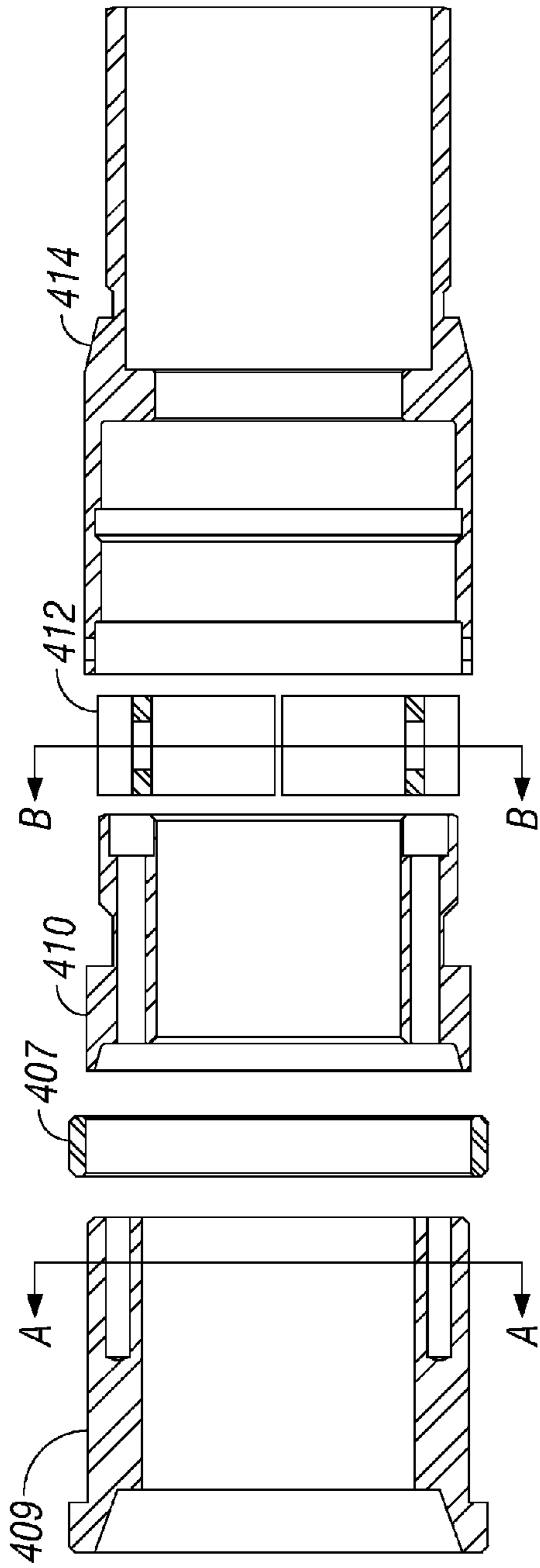


FIG. 4F

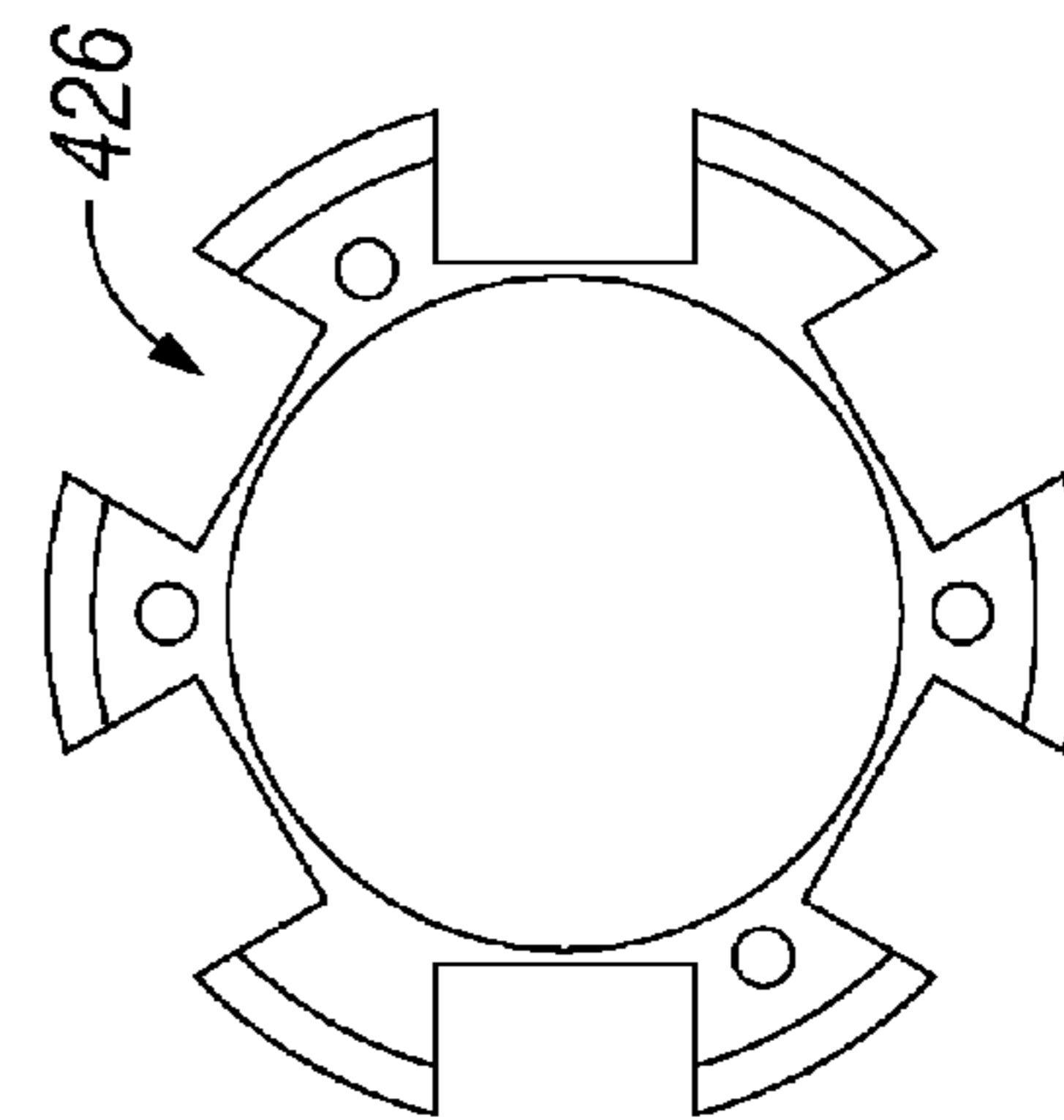


FIG. 4G



FIG. 4H

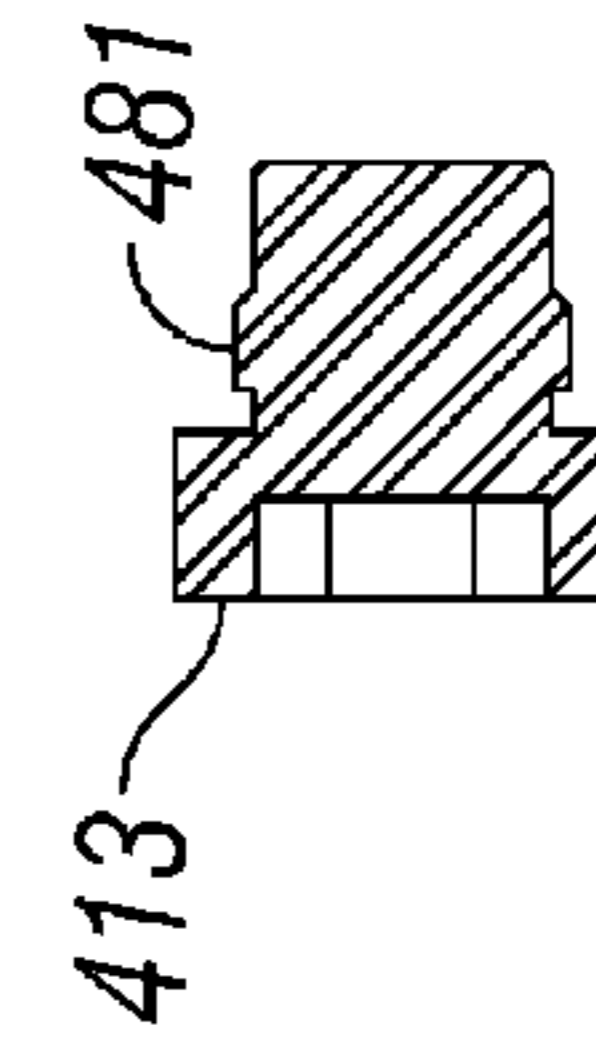


FIG. 4I

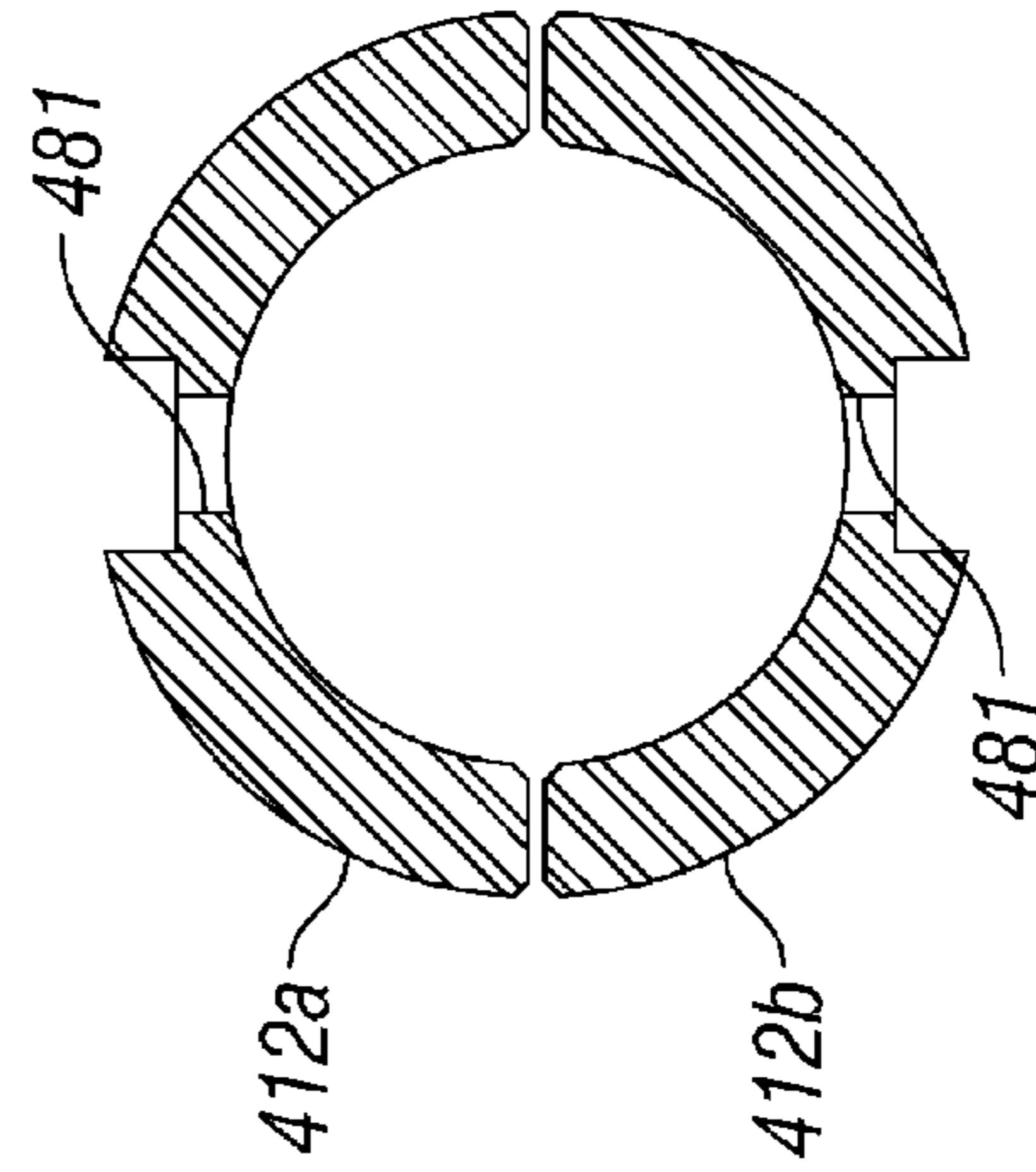


FIG. 4J

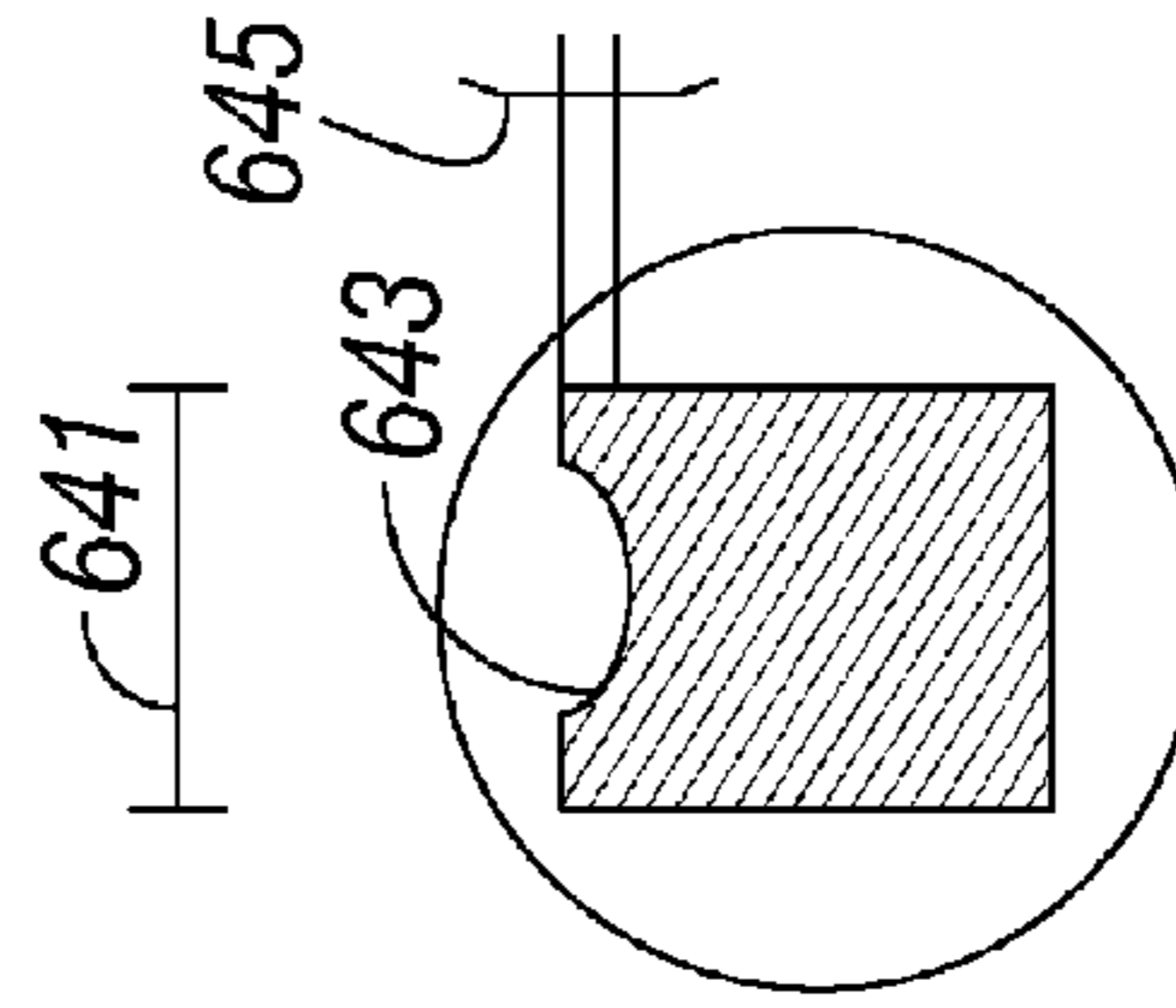


FIG. 4K

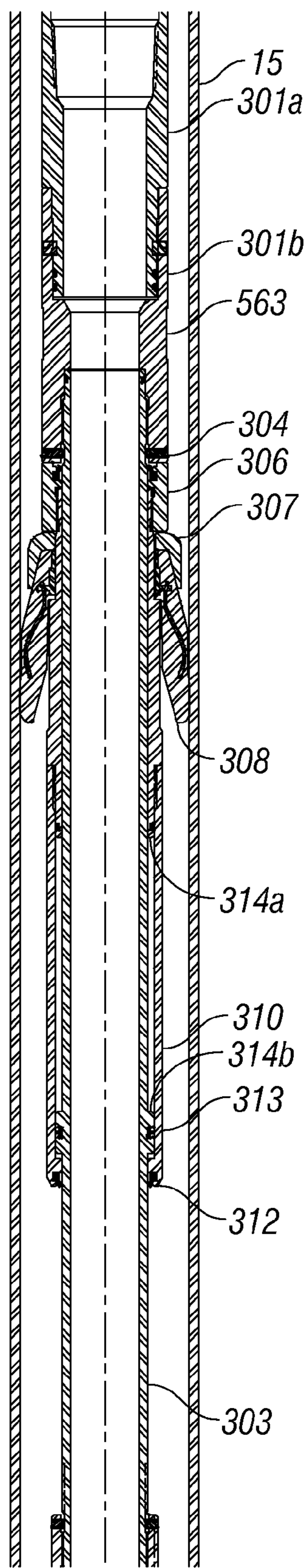


FIG. 5A

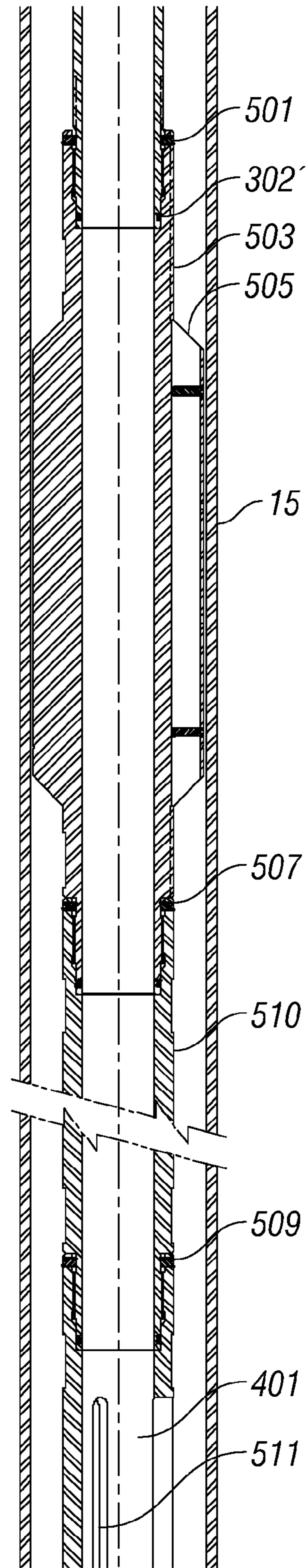


FIG. 5B

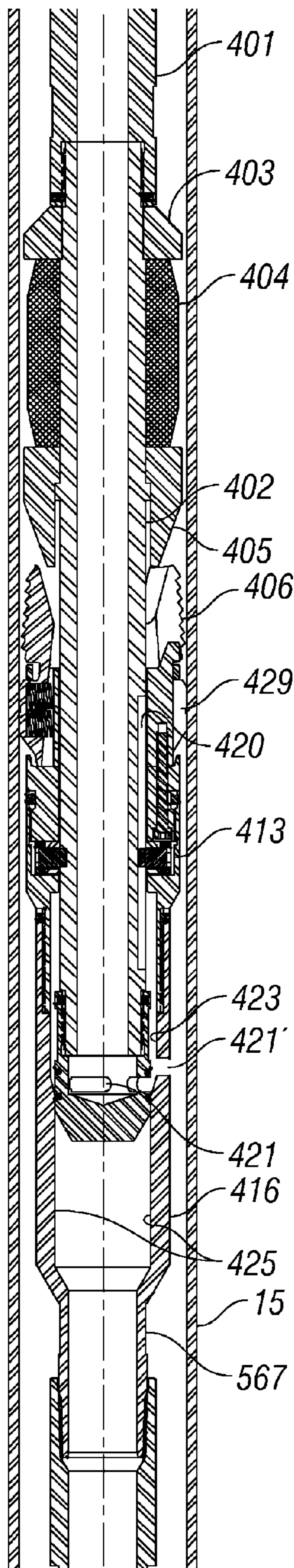


FIG. 5C

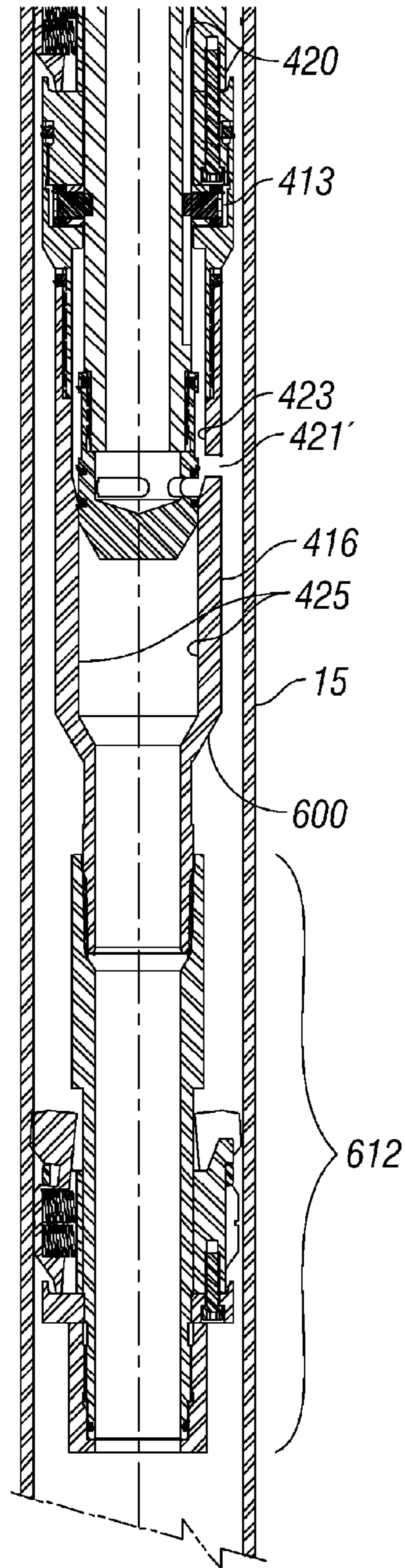


FIG. 5D

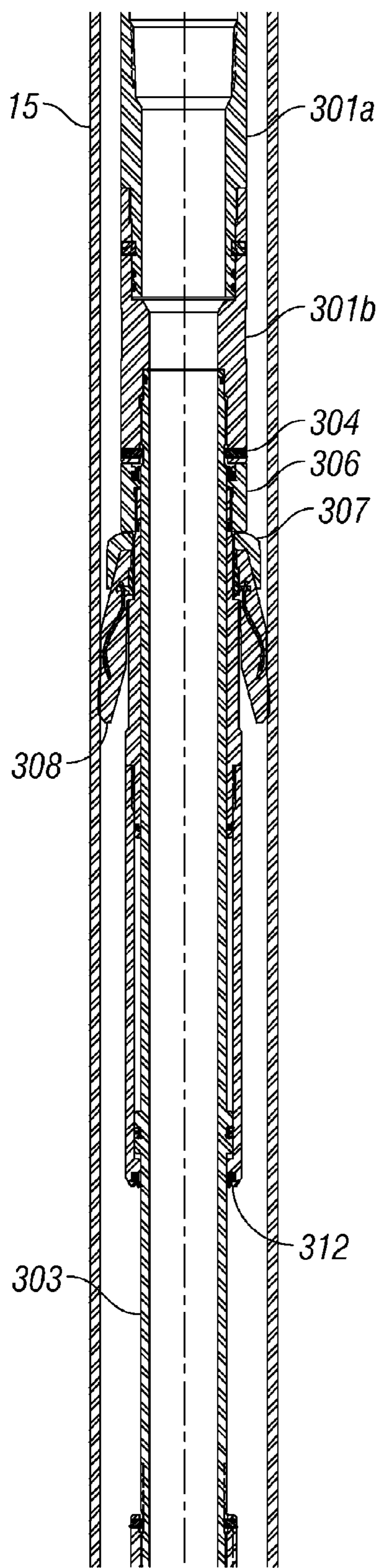


FIG. 6A

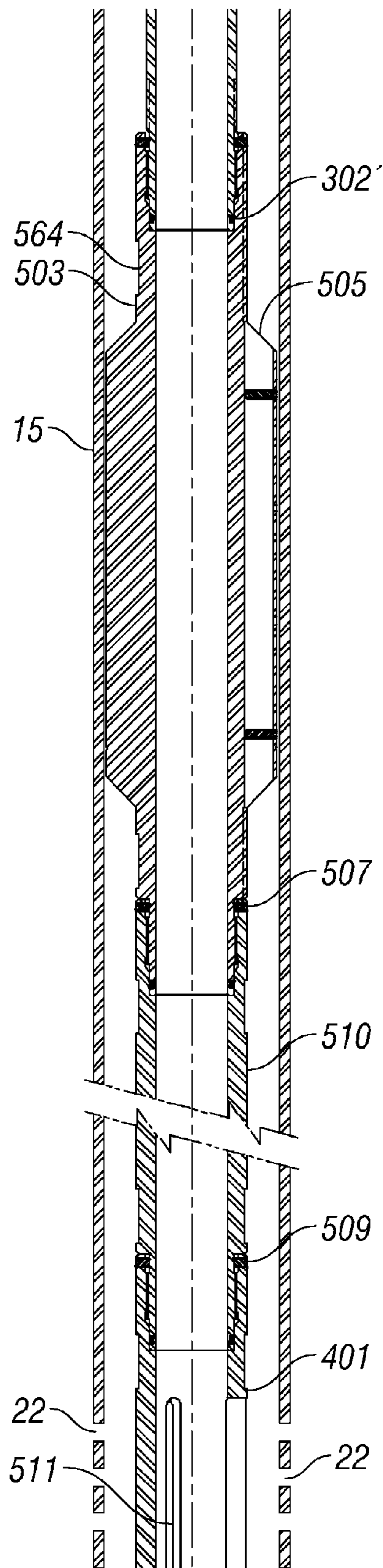


FIG. 6B

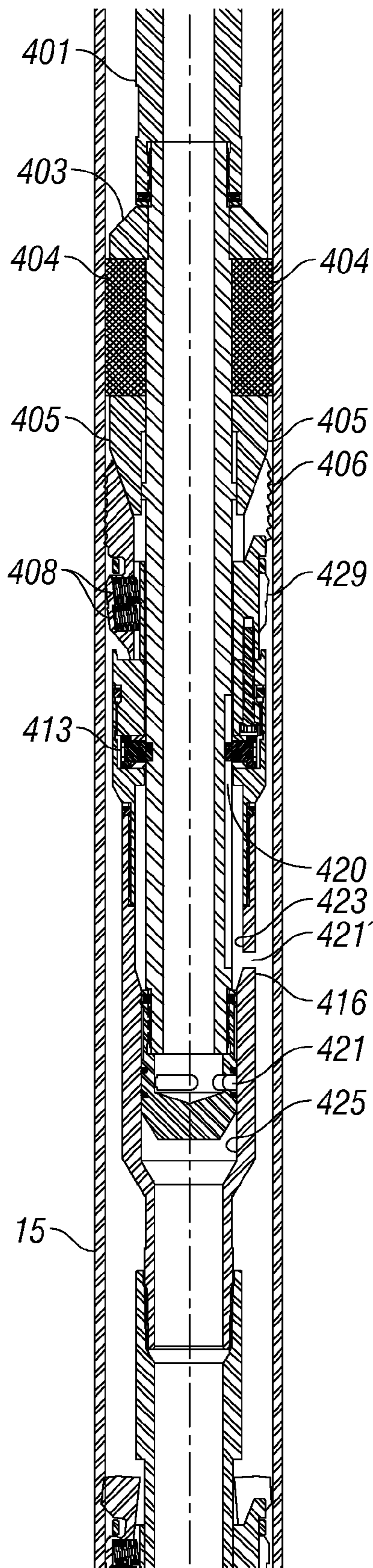


FIG. 6C

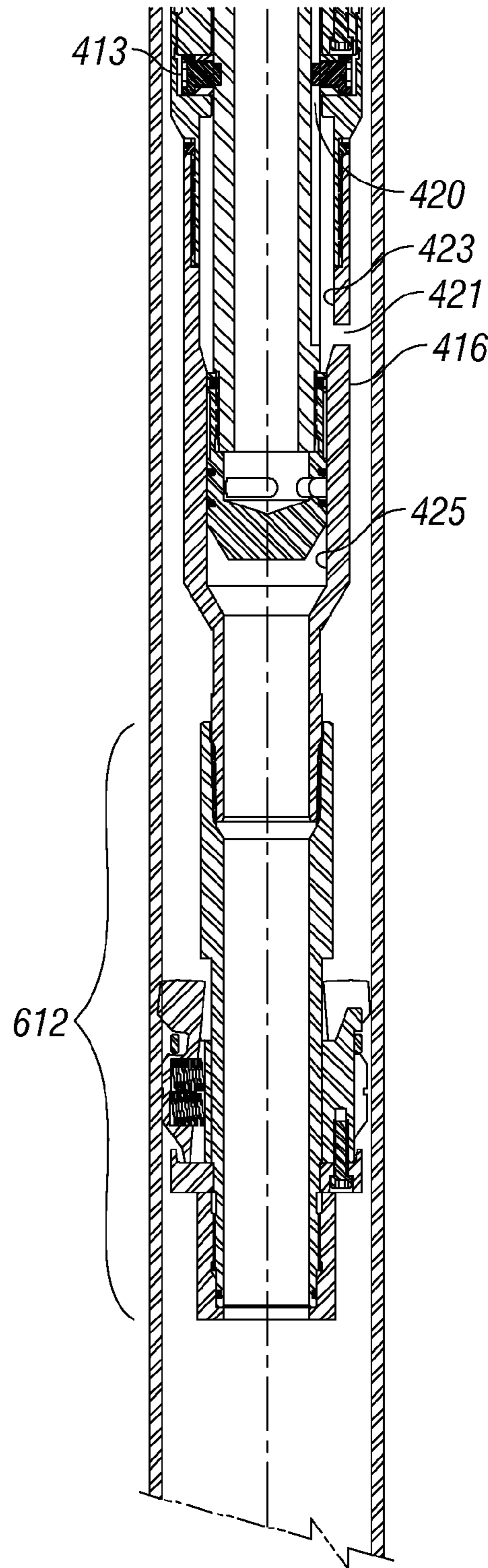


FIG. 6D

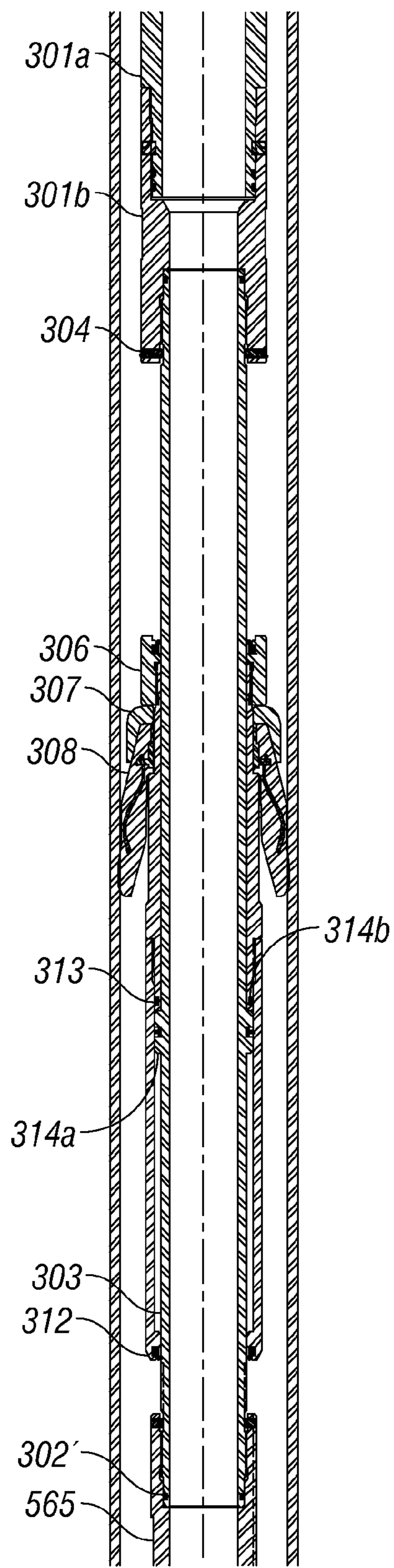


FIG. 7A

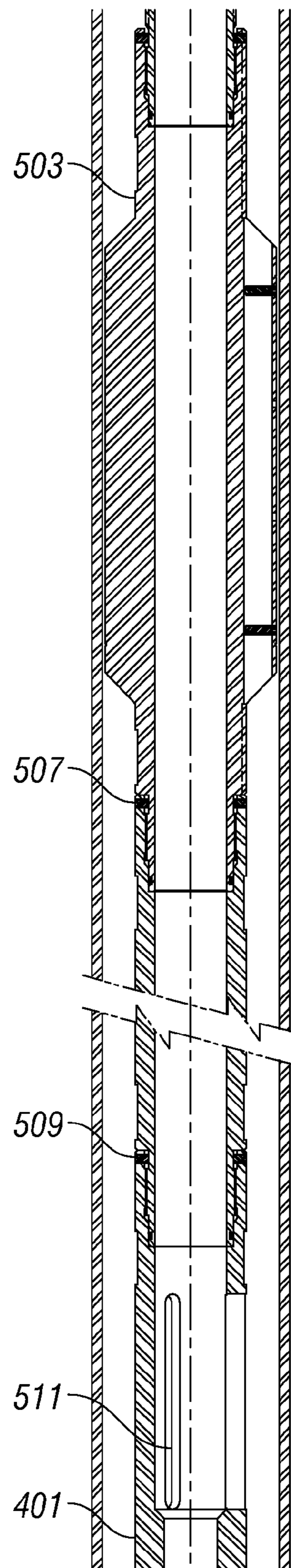


FIG. 7B

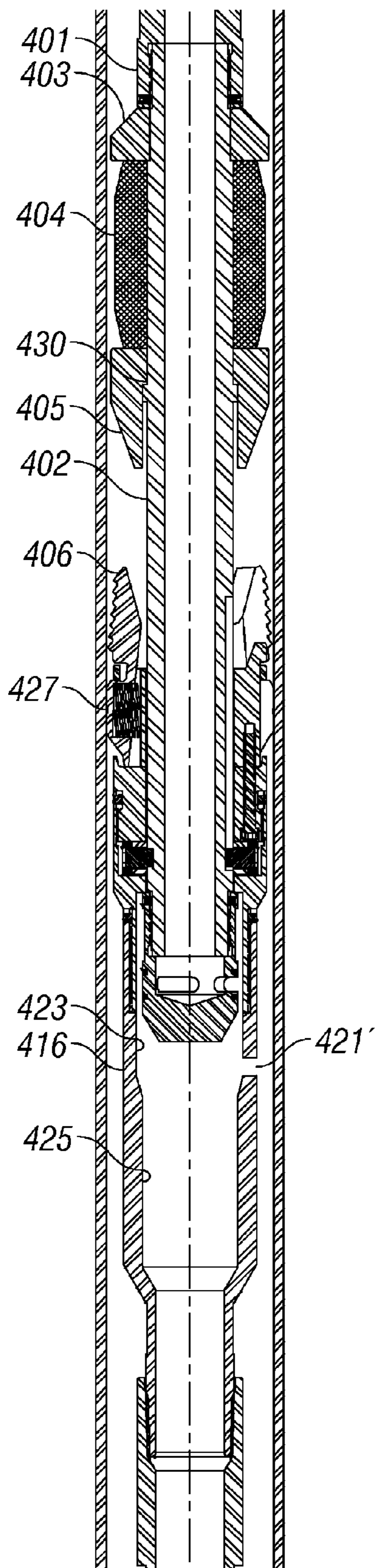


FIG. 7C

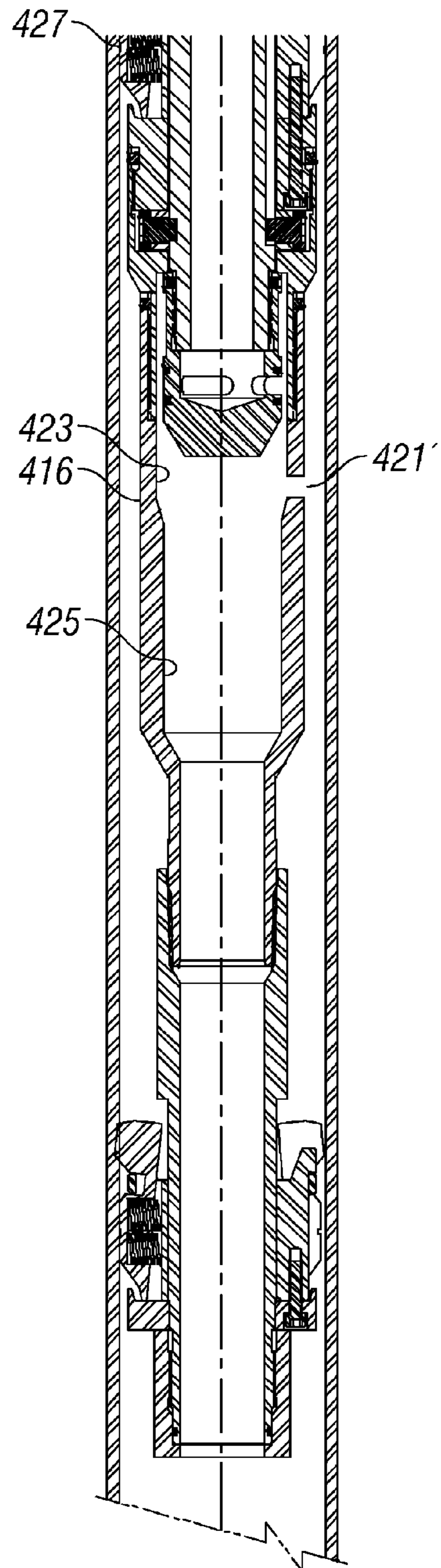
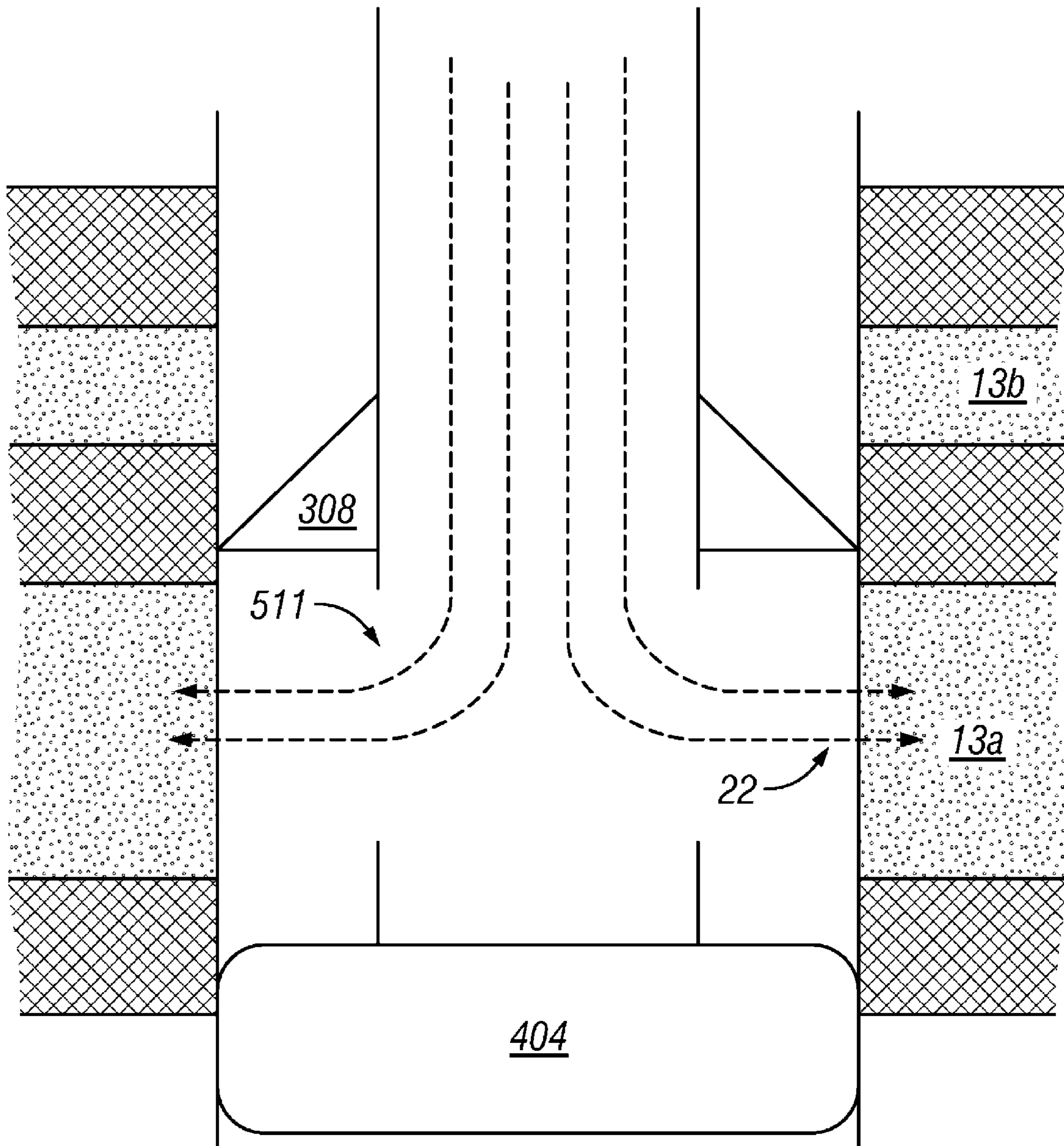
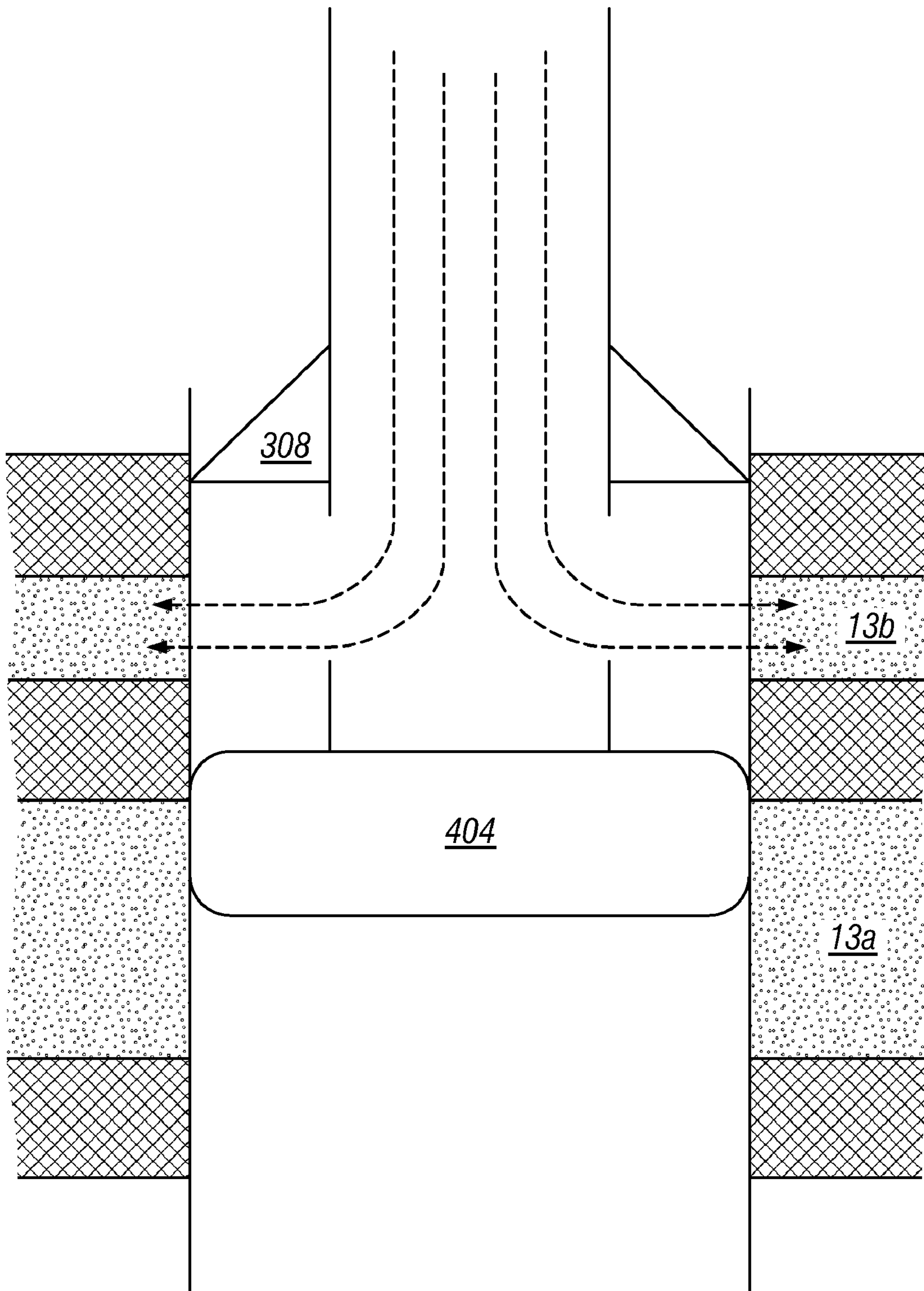


FIG. 7D

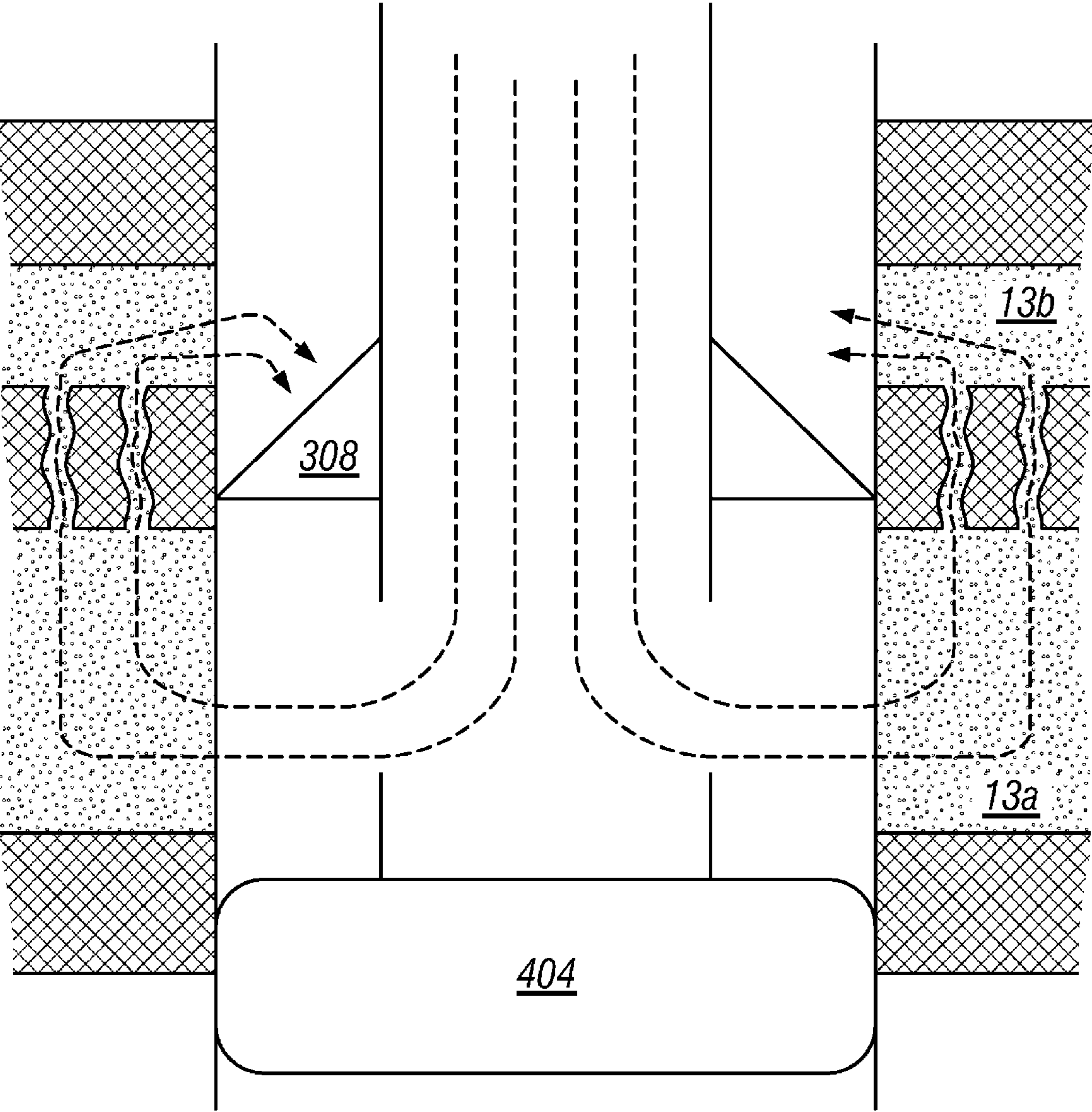


**FIG. 8A**

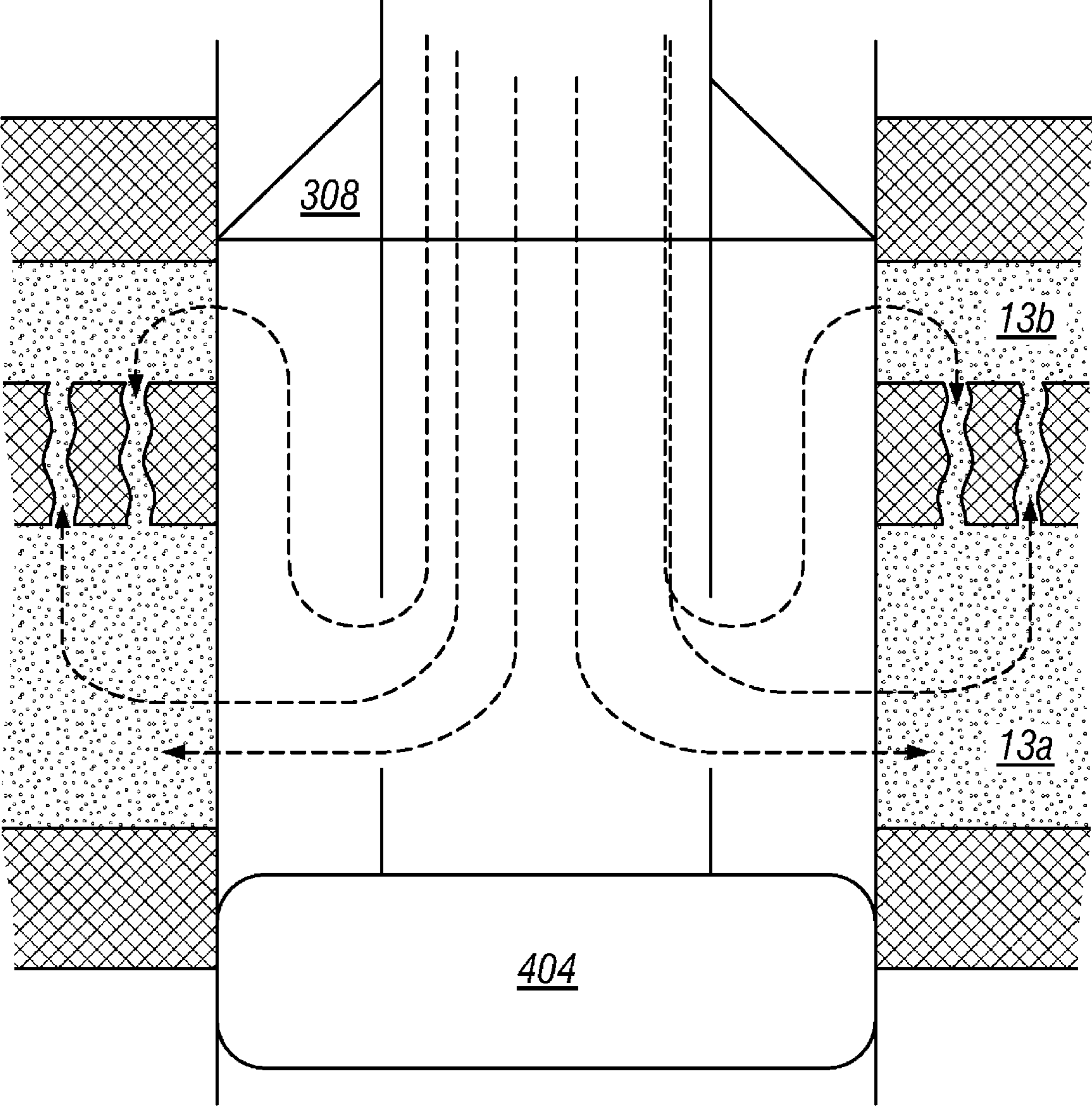




**FIG. 8B**



**FIG. 9**



**FIG. 10**

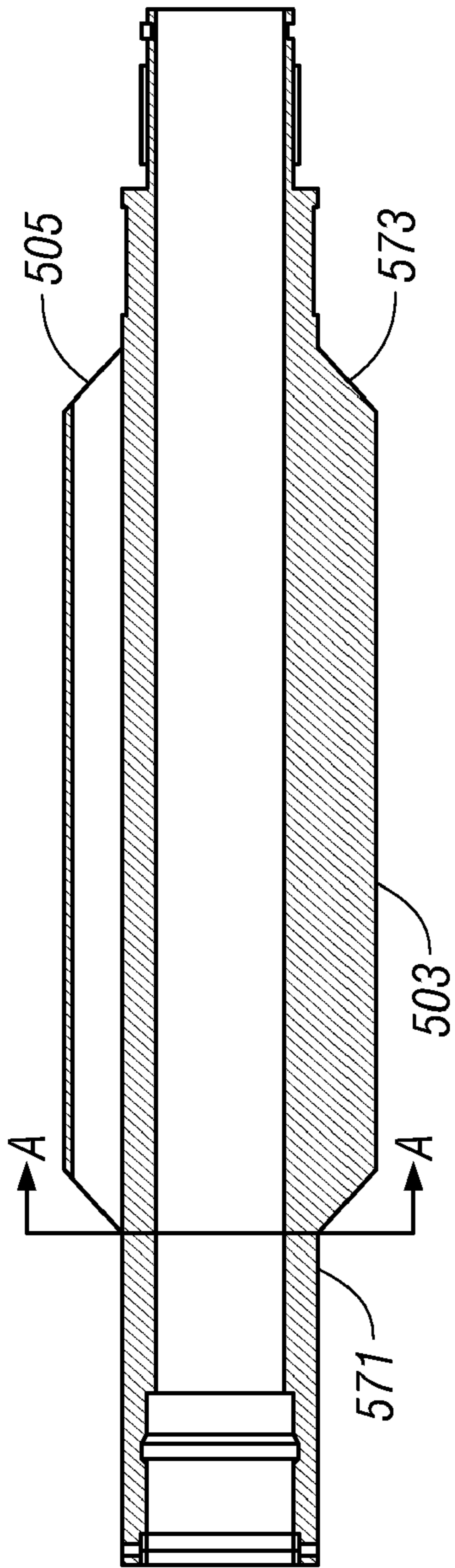


FIG. 11A

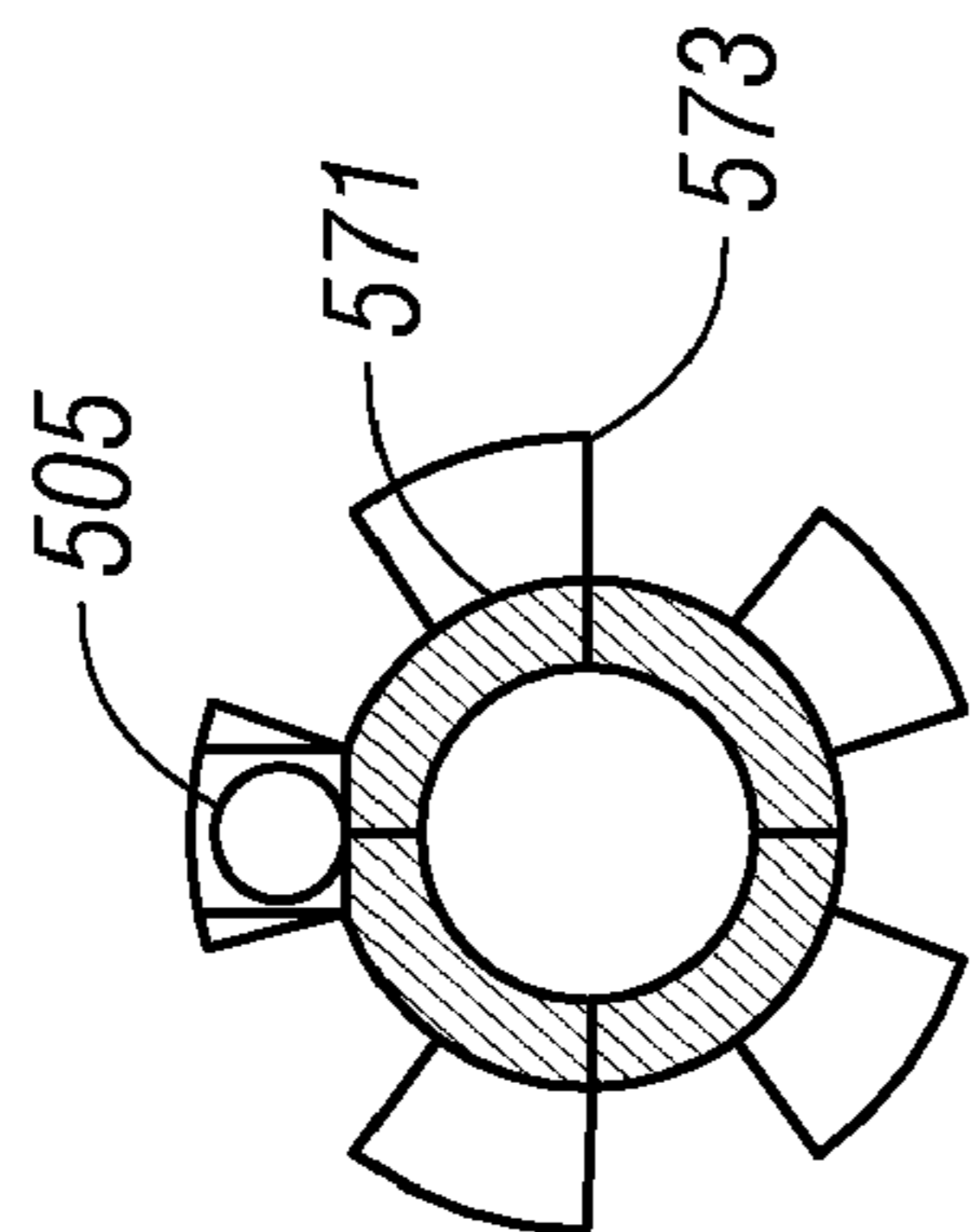


FIG. 11B

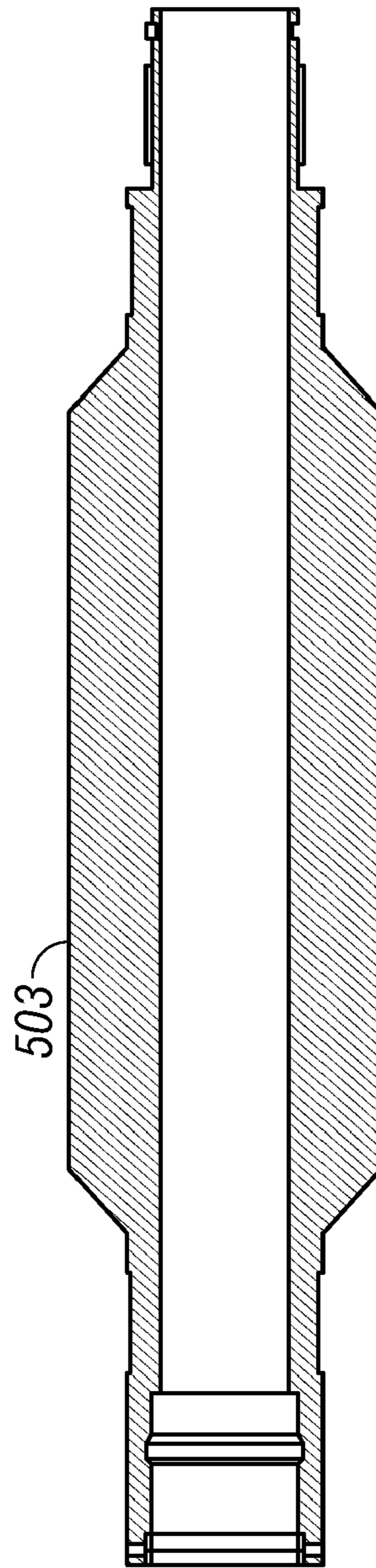


FIG. 11C

## WELL TREATMENT DEVICE, METHOD AND SYSTEM

### BACKGROUND

The invention relates to tools and methods of treatment of well-bores that are used, for example, in the exploration and production of oil and gas.

In many of the well-bores (as illustrated, for example, in U.S. Pat. No. 6,474,419, incorporated herein by reference) so-called "packers" are run in on a work string (for example, coiled tubing), to allow for treatment of the well-bore by perforation of casing and/or fracturing operations. The packers become stuck in the well-bore, however, resulting in lost tools and, sometimes, loss of the entire well.

There is a need, therefore, for improved well treatment devices, systems, and methods.

### SUMMARY OF THE INVENTION

It is an object of at least some examples of the present invention to provide for well-treatment devices, systems, and methods, that reduce the chance of having a tool stuck in a well and/or for more efficient well-treatment procedures.

In at least one example of the invention, a method is provided for treatment of at least one region in a well, the method comprising:

positioning, in a well-bore, a first packer above the region of the well-bore,  
fixing, below the region, an expansion packer,  
treating the region,  
moving the expansion packer longitudinally in the well, and  
moving the first packer after the moving of the expansion packer.

In at least one, more specific example, the moving of the expansion packer comprises longitudinally moving a mandrel with respect to the first packer. In a more specific example, the moving of the expansion packer comprises movement of a packer mandrel and a first packer mandrel wherein the first packer mandrel slides within a first packer sleeve. In an even more specific example, the first packer comprises a cup packer; in at least some alternative examples, the first packer comprises an expansion packer (for example, a compressible expansion packer).

In still a more specific example, a further step is provided of opening a valve, thereby communicating the region with the portion of the well-bore below the expansion packer, wherein the opening is caused by movement of the packer mandrel. In at least one such example, the opening a valve occurs below the expansion packer.

In a further example, the step of moving the first packer comprises, first, lowering the first packer below the treated region, and the step of moving the first packer then comprises raising the first packer after the step of lowering the first packer.

According to still another example of the invention, a system is provided for treatment of the region in a well, the system comprising: a first packer, a first packer mandrel disposed radially inward of the first packer, an expansion packer, an expansion packer mandrel disposed radially inward of the expansion packer, means for treating the region, wherein the means for treating the region is disposed between the first packer and the expansion packer, means for moving the expansion packer, and means for moving the first packer after the moving of the expansion packer.

In at least one such system, the means for moving of the expansion packer comprises means for longitudinally moving a mandrel with respect to the first packer. In a further system, the means for moving of the expansion packer comprises a packer mandrel having a substantially rigid connection (either direct or indirect) a first packer mandrel, wherein the first packer mandrel slides within the first packer sleeve. In at least one further example, a means is provided for equalizing pressure above and below the expansion packer before the moving of the first packer. In some such examples, the means for equalizing comprises a valve operated by movement of the packer mandrel and communicating the region with a portion of the well-bore below the expansion packer. At least one acceptable valve comprises an opening below the expansion packer.

In still a further example, the means for treating the region comprises a substantially cylindrical member having slots disposed therein.

In yet other examples, means for moving the expansion packer comprises a shoulder on the mandrel engaging a guide, and the means for moving the first packer after the moving of the expansion packer comprises:

a first packer sleeve slideably mounted on the first packer mandrel,  
a shoulder on the mandrel, and  
a shoulder on the first packer sleeve disposed to stop longitudinal movement of the shoulder on the mandrel.

According to another example of the invention, a packer system is provided comprising:

a mandrel,  
a sleeve disposed around the mandrel in a longitudinally sliding relation, and  
a packer element fixed to the sleeve.

In at least one such example, a shoulder resides on the sleeve abutting a shoulder on the packer element; a thimble engages the packer element at a first thimble surface; and a retainer ring is threaded on the sleeve. The retaining ring engages the thimble on a second thimble surface. In still another example, a first wiper ring is attached to a first end of the sleeve, and a second wiper ring is attached to the retainer ring. In at least some such examples, a seal is disposed between the sleeve end of the housing.

In some further examples, the sleeve comprises a packer element carrier section having an outer threaded diameter and a stroke housing, the stroke housing having an inner threaded diameter engaging the outer threaded diameter of the packer element carrier. In even further examples, a wiper is connected to an interior diameter of the stroke housing; a seal is disposed between the stroke housing and the mandrel; and a seal is disposed between the stroke housing and the packer element carrier section. In at least some such examples, the packer element carrier section comprises a shoulder; the packer element is disposed between the shoulder and a retainer; and the retainer is threaded to the packer element carrier. In at least one example, a debris barrier is disposed in an interior surface of the retainer. In some examples, the packer element comprises a cup packer element. In further examples, the packer element comprises an expansion packer (e.g. compressible) element. According to still a further example of the invention, a method is provided for treating a well, the method comprising:

positioning a compressible expansion packer in the well-bore, the expansion packer being rigidly-connected to an expansion packer mandrel connect to a work string,  
setting the expansion packer in the well-bore with a longitudinal motion of the work string,

treating the well,  
opening a valve below the expansion packer with a further  
longitudinal motion of the work string, and  
raising the packer.

At least one such method further comprises positioning a  
packer in the well-bore above the expansion packer, rigidly  
connected to a cup packer sleeve. The cup packer sleeve is  
slideably connected to a cup packer mandrel, and the cup  
packer mandrel is connected to the work string and to the  
packer mandrel (at least indirectly).

In at least a further example of the invention, a system is  
provided for treating a well-bore on a work string, the system  
comprising:

an expansion packer mandrel for substantially rigid-con-  
nection to the work string,  
means for setting a compressible expansion packer in a  
well-bore with a longitudinal motion of the work string,  
means for treating the well,  
means, below the expansion packer, for equalizing a pres-  
sure differential across the expansion packer, and  
means for raising the expansion packer.

In at least one such example, the means for setting the  
compressible expansion packer comprises at least one J-slot  
on the expansion packer mandrel interacting with at least one  
J-pin on a slip ring disposed about the expansion packer  
mandrel. In at least a further example, the means for treating  
the well comprises a substantially cylindrical member having  
slots therein.

In still another non-limiting example, the means for equal-  
izing comprises a valve.

In yet a further example, the means for raising the expan-  
sion packer comprises a stop surface (e.g., a shoulder) on the  
mandrel and a stop surface on the expansion packer, wherein  
the stop surfaces interact to cause the expansion packer to be  
raised during vertical motion of the expansion packer man-  
drel.

In still another example of the invention, a method is pro-  
vided for treating multiple zones in a cased well-bore, the  
method comprising:

fixing an expansion packer of a work string below a first  
zone,  
perforating the cased well-bore above the expansion  
packer,  
applying between the work string and the cased well-bore,  
a stimulation fluid through the perforated well-bore,  
equalizing the pressure above and below the expansion  
packer,  
fixing the expansion packer at a second zone, the second  
zone being over the first zone,  
perforating the cased well-bore above the expansion  
packer,  
applying, between the work string and the cased well-bore,  
a stimulation fluid through the perforated well-bore,  
equalizing the pressure above and below the expansion  
packer, and  
raising the expansion packer.

In at least one such method the equalizing comprises open-  
ing a valve below the expansion packer. In a further example,  
the opening comprises moving a valve port connected to an  
expansion packer mandrel from contact with a valve seat  
connected to a drag sleeve.

Still a further example of the invention provides a system  
for treating multiple zones in a cased well-bore, the system  
comprising:

means for perforating the cased well-bore above the expan-  
sion packer,

means for applying, between the work string and the cased  
well-bore, a stimulation fluid (e.g. fracturing fluid, foam, etc.)  
through the perforated well-bore,

means for equalizing the pressure above and below the  
expansion packer, and

means for raising the expansion packer.

In at least one such system, the means for equalizing com-  
prises a valve below the expansion packer. In a further system,  
the means for equalizing also comprises a valve port con-  
nected (directly or indirectly) to an expansion packer man-  
drel, the valve port reciprocating from contact with a valve  
seat connected to a drag sleeve. In still another example, the  
means for perforating the cased well comprises a jetting tool;  
while, in yet another example, the means for applying com-  
prises a surface pump connected between the well casing and  
the work string, and the means for raising the expansion  
packer comprises a connection between an expansion packer  
guide and an expansion packer mandrel.

An even further example of the invention provides an  
expansion packer device comprising:

a mandrel having a substantially cylindrical bore there-  
through,  
a compressible packer element disposed about the man-  
drel,  
a set of casing-engaging elements disposed about the man-  
drel,  
a set of drag elements disposed about the mandrel,  
a set of slots in an outer surface of the mandrel,  
a set of slot-engaging elements engaging the set of slots and  
disposed about the mandrel, the slot-engaging elements  
being longitudinally and radially moveable about the  
mandrel,  
a valve port located outside the cylindrical bore and below  
the set of slots, and  
a valve seat located outside the valve port.

In at least one such expansion packer, the valve port is  
located below the mandrel. In a further example of the inven-  
tion, a drag sleeve is provided in a longitudinally-slideable  
relation to the mandrel, and the drag sleeve comprises the  
valve seat. In yet a further example, the drag sleeve further  
comprises openings above the valve seat. In still another  
example, the valve seat is longitudinally adjustable with  
respect to the valve port. In an even further example, the valve  
port is located below the mandrel and is positioned between  
elastomer, grooved seals that have, for example, a concave  
surface.

In at least one example, the drag sleeve also comprises: a  
slide member in longitudinally-slideable engagement with  
the mandrel and a seat housing, longitudinally and adjustably  
attached to the slide member. In at least one such example, the  
seat housing is threaded to the slide member. In a further such  
example, rotation of the seat housing on threads connecting  
the seat housing to the slide member adjusts a longitudinal  
distance the valve ports travel to engage the valve seat.

Still another example of the invention provides a well  
fracturing tool comprising:

a cylinder having longitudinal slots therein,  
threads located at a packer-engaging end of the cylinder,  
wherein a portion of the slots located closest to the packer-  
engaging end is between about 10" and about 14" from  
the packer-engaging end.

In at least one such tool, the portion of the slots located  
closest to the packer-engaging end is about 13" from the  
packer-engaging end.

The above list of examples is not given by way of limita-  
tion. Other examples and substitutes for the listed compo-  
nents of the examples will occur to those of skill in the art.

Further, as used throughout this document the description of relative positions between parts that relate to vertical position are also intended to apply to non-vertical well bores. For example, in a well-bore having a slanted component, or even a horizontal component, a port is "above" or "over" another port if it is closer (along the well-bore) to the surface than the other port. Thus, a cup packer that is in a horizontal well-bore is "above" an expansion packer in the same well-bore if, when the cup packer is removed from the well-bore, it precedes the expansion packer.

#### DETAILED DESCRIPTION OF THE DRAWINGS

FIG. 1 is a side view of an example embodiment of the invention.

FIG. 1A is a side view of an enlargement of a portion of the example of FIG. 1.

FIG. 2 is a side view of a set of enlargements of a portion of the example of FIGS. 1 and 1A.

FIG. 3 is a sectional view of a portion of an example of the invention.

FIGS. 3A-3D are sectional views of a portion of an example of the invention.

FIG. 4 is a sectional view of a portion of an example of the invention.

FIGS. 4A-4B are sectional views of a portion of an example of the invention.

FIG. 4C is a flattened view of a portion of a surface of a cylindrical member example of the invention.

FIGS. 4D-4K are sectional views of a portion of an example of the invention.

FIGS. 5A-5D are sectional views of an example of the invention in a "run-in" state.

FIGS. 6A-6D are sectional views of an example of the invention in a "treat" state.

FIGS. 7A-7D are sectional views of an example of the invention in a "pressure relief" state.

FIGS. 8A-8B are side views of an example of the invention treating multiple strata.

FIGS. 9-10 are side views of an example method of use according to an example of the invention.

FIGS. 11A-11C are sectional views of an example of the invention.

#### DETAILED DESCRIPTION OF EXAMPLE EMBODIMENTS

Referring now to FIG. 1, a well-site, generally designated by the numeral 1, is seen. In the figure, a well-head 5 that is attached to the ground 3 has blow-out preventers 7 attached to the well head 5. A lubricator 9 is seen connected under injector 11 that injects coiled tubing 12, through lubricator 9, blow-out preventer 7, well-head 5, and into the well-bore. In many situations, the well-bore is cased with casing 15. Seen in the well-bore at an oil and/or gas, strata 13 is an example of the present invention straddling the oil and/or gas strata 13.

In FIG. 1A, an enlargement of the example from FIG. 1 is seen in which a cup packer 308 is connected through centralizer section 503, spacer joint 510, ported section 511, expansion packer section 404, and well-bore engagement section 701. FIG. 2 and FIGS. 2A-2F show enlargements of each of the sections discussed above.

Referring now to FIG. 3, a cross-section of an example cup-packer assembly is seen comprising a top connector section 301 that is connected by threads to mandrel 303. A socket set screw 304 prevents connector 301 and mandrel 303 from unscrewing. An O-ring seal 302 (for example, an SAE size

68-227, NBR90 Shore A, 225 PSI tensile, 175% elongation, increases the pressure that can be handled by the assembly, allowing a relatively low pressure thread 317 for the connector.) In at least one example, thread 317 comprises \*2.500-8 STUD ACME 2G, major diameter 2.500/2.494, pitch diameter 2.450/2.430, minor diameter 2.405/2.385, blunt start thread. As used in this example, many of the dimensions (and even other threads) have been found useful in the design of a 5½" casing tool. Similar dimensions, threaded connections, etc., are used in the examples seen in the figures, which will not be described in detail, that also allow for lower pressure treads with secondary seals to be used. Other dimensions and pressure sealing arrangements will be used in other size tools (for example, 4½" and 7" tools) and other pressure considerations that will occur to those of skill in the art.

Further, connections other than threads, and/or other materials, will be used by those of skill in the art without departing from the invention. In at least one example of the parts seen in the figures, the following rules of thumb are observed (dimensions in inches): (1) machined surfaces .X-.XX 250 RMS, .XXX 125 RMS, (2) inside radii 0.030-0.060; (3) corner breaks 0.015×45°; (4) concentricity between 2 machined surfaces within 0.015 T.I.R.; (5) normality, squareness, parallelism of machined surfaces 0.005 per inch to a max of 0.030 for a single surface; (6) all thread entry & exit angles to be 25°-45° off of thread axis. A thread surface finish of 125 is acceptable. Materials useful in many examples of the invention include: 4140-4145 steel, 110,000 MYS, 30-36c HRc. Other rules of thumb that will be useful in other embodiments will occur to others of skill in the art, again without departing from the invention.

In the example shown, cup retainer 306 holds thimble 307 against cup element 308, which is, itself, held against a shoulder 314a of cup carrier sleeve 309. Cup retainer 306 is threaded to cup carrier sleeve 309, causing cup element 308 to be slideably mounted along and around mandrel 303. Being slideable around mandrel 303 allows cup element 308 to spin, allowing it to clear debris more easily than if it were not able to move in that dimension.

Cup carrier sleeve 309 is connected, in the illustrated example, by threads and an O-ring seal 313 to stroke housing 310. A piston-T-seal (for example, a Parker 4115-B001-TP031) prevents flow of fluid and pressure from entering between stroke housing 310 and mandrel 303. By using a low-pressure thread (such as an "SB" thread), a wide torque range is enabled, which allows "make up" of the work string with smaller tools. A wiper ring (for example, Parker SHU-2500) is used at the end of stroke housing 310. Similarly, wiper ring 305 also operates as a debris-barrier.

In operation, which is described more below, cup element 308 slides on cup holder 309 about mandrel 303. Shoulder 314a of cup carrier sleeve 309 and shoulder 314b of mandrel 303 define the travel distance that the mandrel 303 and cup carrier sleeve 309 are able to slide, longitudinally, with respect to each other. Since connector 301 is fixed longitudinally to mandrel 303, if the coiled tubing (which is attached to connector 301) is pulled from above, mandrel 303 will move upward and slide within cup sleeve carrier 309; therefore, cup element 308 does not have to move in order to move mandrel 303. Therefore, tools (such as expansion-packers) that are below cup element 308 can be manipulated longitudinally without the need to move a cup packer fixed above them.

In at least one example, an expansion packer that is longitudinally operable with J-slots is used, and the travel distance is sufficient to allow a stroke that is larger than the length of the J-slots. It has been found that it is especially useful to allow some distance greater than the J-slots because, when an

expansion packer is being positioned and set, drag elements on the packer (e.g., springs, pads, etc.) will slip. For a 5½" tool, for example, about 10" has been found to be sufficient for the travel distance between shoulders **314a** and **314b** to allow for a 6" J-slot travel.

Referring now to FIG. 4, an example expansion packer assembly is seen. In the illustrated example, expansion packer mandrel **402** is connected by threads backed by a set screw **417** to an upper element **401** (for example, a slotted "sub" used for applying fracturing fluid in some examples). Therefore, when the work string is lifted from above, expansion packer mandrel **402** is lifted. Expansion packer mandrel **402** includes a shoulder **430** against which setting cone **405** abuts. Expansion packer element **404** is slid up against setting cone **405**, and guide ring **403** is slid up against expansion packer element **404**. The attachment of upper element **401** against guide **403** holds guide **403** against a shoulder **432** in mandrel **402**; and, therefore, when setting cone **405** is pushed toward guide **403**, longitudinally, element **404** is compressed and expands radially outward from mandrel **402**, due to the rigid connection of guide **403** backed by upper element **401**. Likewise, when mandrel **402** is lifted from above, shoulder **432** causes guide **403** to move longitudinally away from setting cone **405**, allowing decompression and elongation of packer element **404**.

In operation, when a cup packer is set (as seen in FIG. 1) above an oil and/or gas containing strata **13**, and an expansion packer is set below an oil and/or gas containing strata **13**, well treatment (for example, perforation and/or fracturing operations) occur. After treatment, it is desirable to move the expansion packer and/or the cup packer. However, many times, there is a pressure differential across the expansion packer. To relieve that pressure differential, at least one valve port **421** is provided outside of the mandrel **402**.

In the illustrated example, port **421** operates with a valve-seat surface **425** (which has a diameter less than the diameter of surface **423** above openings **421'**). Openings **421'** are located in equalizing sleeve **416**. Ports **421** are provided, in the illustrated example, by threading equalizing housing **600** onto mandrel **402**; a set screw is again used to prevent the elements from becoming detached. Referring now to FIG. 4D, ports **421** are sealed against surface **425** in equalizing sleeve **416** (FIG. 4E) by seals **602a-602d** (for example, nitrile elastomer between about 70 to 90 shore hardness; in higher temperature viton elastomer). Other elastomers will occur to those of skill in the art. In some examples, the seal material consists essentially of NBR 80 shore A, 2000 PSI Tensile, 300% Elongation. Further, a concave is seen in seals **602a-602d**. Such a concave allows a reduction of force needed to put the seal into the seal bore. The dimensions of the seals **602a-602d** in some examples are substantially the same as if two O-rings were located in housing **600**; for example, the concave in seals **602a-602d** is about the same size as the gap that would be formed by two o-rings positioned side-by-side.

FIG. 4K shows an example of seals **602a-602d**. For an equalizing housing **600** having a diameter between about 2.640 inches to about 2.645 inches (which is particularly useful in a 4½" tool), with a groove width of between about 0.145" and about 0.155", and seals **602a-602d** have a protrusion distance **645** of about 0.020 inches from housing **600**, while the radius of curvature of concave surface **643** is about 0.06 inches. In at least one 5½" tool example, grooves **603a-603d** are between about 0.145 inches and about 0.155 inches, and the radius of curvature of groove surface **643** is about 0.06 inches.

It will be noted that there is no requirement for a "longitudinal opening" of the type described in U.S. Pat. No. 6,474,

419, nor is there a need for a valve extending up into the packer mandrel. A significant advantage of the example valve ports being, outside the mandrel (and, in at least some cases, below the mandrel) is that a larger flow path is available than with valves located within the mandrel. This allows the tool to be run in the well-bore faster and causes the tool to have less problems with debris.

Referring again to FIGS. 4 and 4F (taken through line "A" of FIG. 4G), **4G**, **4H**, **4I**, and **4J**, equalizing sleeve **416** is connected by threads to lower component **414** that is slidably mounted (longitudinally and radially in the example shown) around mandrel **402**. Lower component **414** covers J-pins **413** that engage a J-slot **420** that is formed in the surface of mandrel **402**. J-pins **413** are held in a slip-ring **412** (described in more detail below) that spins around mandrel **402**. Threaded to lower component **414** is a slip-stop-ring **410**. Again, a set screw **418** prevents lower component **414** and slip-stop-ring **410** from unscrewing. Slip-stop-ring **410** is seen in the top portion of FIG. 4 connected to slip ring **409** by slip ring screw **411** (for example, ASME B 18.3 hexagon socket-cap head-screw, 5½"-18 UNTC×2.750 long, ASTM A574 alloy steel).

On the bottom of FIG. 4, 180° from slip ring screw **411**, slip springs **408** are seen. Springs **408** reside in channel **426** and bias rocker slip **406** against rocker slip retaining ring **407**; the biasing action of springs **408** operates against retaining ring **407**, causing rocker slip **406** to be biased toward mandrel **402**. Therefore, when the packer assembly is being run into the well-bore, the teeth on rocker slip **406** are not engaged with the well-bore.

Referring now to FIG. 4A, mandrel **402** is seen alone, where shoulder **430** and shoulder **401** are more easily seen. Further, J-slot **420** is seen machined into the surface of mandrel **402**, in the illustrated example.

FIG. 4B shows the actual shape of J-slot **402**, which is formed (e.g., machined) circumferentially around mandrel **402**. The top line **461** and bottom line **461'** actually do not exist. Those are the lines on which the J-slot **420** joins on the outside of mandrel **402**.

FIG. 4F shows slip ring **412**, which, in the example embodiment of FIG. 4J (taken along line B of FIG. 4F) comprises two halves, **412a** and **412b**, each of which includes a threaded receptacle **481** that mates with threads **483** of J-pin **413** (FIG. 4I). Fixing J-pins to slip ring **412**, rather than floating them without a substantially fixed, radial connection, reduces wear and other problems caused by debris interfering between J-pins **413** and slip ring **412**.

With the two J-pins **413** (FIG. 4), each set 180° apart, there are three states for the expansion packer assembly, depending on where the J-pins are located. During the process in which the expansion packer is being run into the well-bore, the J-pins reside in slot **471**. Once the expansion packer is in place, an operator lifts the work string (e.g. coiled tubing) from the surface, which lifts mandrel **402**. J-pin **413** then shifts from position **471** (FIG. 4B) to position **472**. During that shifting, the drag pads **429** (FIG. 4) of rocker slip **406** cause friction between the rocker slip **406** and the well-bore. This allows the mandrel **402** to move upward and the J-pin to change positions. Mandrel **402** is then pushed down from above, causing J-pin **413** to again shift from position **472** to position **473** (FIG. 4B). This shift causes setting cone **405** (FIG. 4) to engage rocker slips **406**, causing them to move outward and engage the well-bore. Further movement downward of mandrel **402** causes mandrel shoulder **430** (FIG. 4) to move away from setting cone **405**, and expansion packer element **404** expands against the well-bore, sealing the lower portion of the well-bore from the portion of the well-bore



above element **404**. In this position, ports **421** have moved past opening **421'** and are sealed against surface **425**.

When mandrel **402** is again lifted (after treatment operations), J-pin **413** again shifts into position **472** (FIG. 4B), causing ports **421** (FIG. 4) to again be in fluid communication with opening **421'**, and pressure is equalized above and below packer element **404**. As will be seen in more detail below, the alignments of ports **421** with opening **421'** occurs while packer element **404** may still be substantially engaged with the well-bore.

Also, during treatment operations (such as well fracturing, when fluids containing sand may be used), it has been found that the upper cup packer **308** (FIG. 3) can become stuck. However, the cup packer element **308** is mounted on cup carrier sleeve **309**, so that cup mandrel **303** (and, therefore, expansion packer mandrel **402**) can slide without the need to move cup element **308**. This allows the setting and the operation of pressure release below a fixed cup element.

Referring now to FIG. 3A, an assembly view of the cup element assembly is seen. Cup carrier sleeve **309** is positioned to be slid into the cup element assembly such that surface **320a** of the cup element **308** engages surface **320b** of cup carrier sleeve **309**. In various embodiments, cup element **308** comprises an elastomer (for example, an elastomer seal—for example NBR 80 Shore A), and a spring **308a** is imbedded in the elastomer material, mounted to cup element ring **308b**, as shown. In many examples, there is a slight outward taper of the inner surface **308c** of cup element **308**. Thimble **307** holds cup element **308** against cup carrier sleeve **309** by pressing cup surface **316a** against cup carrier sleeve shoulder **316b** by engaging thimble surface **318a** with cup surface **318b**. As mentioned with reference to FIG. 3, the threading of a cup retainer ring **306** onto sleeve **309** at threads **315** holds the thimble **307**, cup element **308** and cup carrier sleeve **309** together.

Referring now to FIG. 3C, the cup carrier sleeve is positioned to be slid over cup mandrel **303** (left to right in the Figure) such that surface **314a** of cup carrier sleeve **309** is stopped by shoulder **314a** of mandrel **303**. A seal **313** is applied around mandrel **303**, as shown. Referring now to FIG. 3B, stroke housing **310** is slid over mandrel **303** (from the right as in the Figure); then, pin threads **319** on cup carrier sleeve **309** mate with box threads **319'** on stroke housing **310**. The connection between cup carrier sleeve **309** and stroke housing **310** is sealed with another seal **313**. At the end of stroke housing **310** a wiper ring (not shown) is mounted in wiper ring receptacle **312** (FIG. 3B). FIG. 3D shows a common seal **313** used in connection with stroke housing **310** and cup carrier sleeve **309**.

Referring to FIGS. 5A-5D, an example of a system is seen in the “run-in” position (that is, the “state” or positions of the components when seen run into a well-bore). In FIG. 5A, connector **301** comprises two components **301a** and **301b**. The form of connector **301** varies depending on a variety of considerations including size, type of work string, treatment method, and other considerations that will occur to those with skill in the art. Cup retainer **306** is run up against connector **301a**, and the cup sleeve carrier and stroke housing are in a compressed position with respect to cup mandrel **303**.

In FIG. 5B, cup mandrel **303** is seen connected to a centralizer **503** that includes a gauge receptacle **505**. In some example embodiments, centralizer **503** does not include a gauge receptacle; however, in the illustrated example, gauge receptacle **505** is provided so that an instrument (for example, a pressure gauge) may be positioned in the well during treatment operations. Having pressure measurements from an area

close to the location of treatment helps interpretations of the quality of the treatment compared with pressure readings taken at the surface.

FIG. 11A shows an example centralizer **503** with gauge receptacle **505** drilled through, as more fully illustrated in FIG. 11B, taken through line “A” of FIG. 11A. There, barrel **571** of centralizer **503** is surrounded by extensions **573**, at least one of which has been drilled through to accept a gauge in receptacle **505**. The gauge is mounted, in various embodiments, in many ways that will occur to those of skill in the art; there is no particularly best way to mount such a gauge in receptacle **505**.

Centralizer **503** is seen in FIG. 5B connected to space cylinder **510**, which is, in turn, connected to ported member **401**, which includes port **511**. For simplicity, not all of ported member **401** is seen in FIG. 5B.

A more complete view of ported member **401** is seen in FIG. 4C, where slots **511** are formed in a generally cylindrical member **401** that includes an erosion zone **551** between slots **511** and also includes a box thread connector end **553** for connection to an expansion packer assembly. The erosion zone **551** allows erosion of the ported member **401** to occur during treatment—rather than having erosion occur to the expansion packer assembly. In a 5½" tool, for example, erosion zone **551** is between about 12 inches and about 15 inches long. An optimal length for erosion zone **551** has been found to be about 13 inches. Also seen in erosion zone **551** are flats **562** machined into member **401** to allow for a tool to engage member **401** in order to thread member **401** to, for example, spacer **510** and connector **301**. Such flats are also provided on other elements (e.g., flats **563** of connector **301B** of FIG. 5A, flats **564** of centralizer **503** of FIG. 6B, flats **565** of spacer **510** of FIG. 7A, and flats **567** of equalizing sleeve **416** of FIG. 5C). Such flats may be provided on other components used in and/or with the present invention.

Referring now to FIG. 5C, a lower portion of ported member **401** is seen connected to expansion packer mandrel **402**. Because J-pin **413** is in position **471** (FIG. 4B) of J-slot **420**, the expansion packer assembly is said to be in a “run-in” position, wherein communication between valve port **421** and opening **421'** allows fluid communication between the inner bores of mandrel **402**, slotted member **401**, spacer cylinder **510**, centralizer **503**, cup packer mandrel **303**, and connector **301** (which is attached, in some examples, to a coiled tubing work string.)

Referring now to FIG. 6A-6D, the system is seen in the treatment position wherein J-pin **413** has been shifted from position **471** to position **472** of FIG. 4B and then to position **473** by, first, lifting on the coiled tubing, which causes the interconnected mandrels to lift with respect to drag pads **429** that drag against well casing **15**. Because of the drag of drag pads **429** mandrel **402** rises, and communication is maintained through ports **421** out of opening **421'**. The raising of mandrel **402** causes J-slot **413** and slip ring **412** rotate so that J-pin **413** will engage position **472** (FIG. 4B). From position **472**, the coiled tubing is lowered, causing mandrel **402** to be lowered with respect to J-pin **413**. Such movement causes J-pin **413** to be directed toward position **473** of J-slot **420** (FIG. 4B), allowing further lowering of mandrel **402**.

The further lowering, best seen in FIG. 6C causes valve ports **421** to be closed against surface **425** and causes setting cone **405** to engage rocker slips **406**. Rocker cone **405** forces rocker slips **406** outward to engage casing **15**, halting the downward motion of setting cone **405**. Further downward motion of mandrel **402** causes guide **403** to compress expansion packer element **404**, which then engages and seals against well casing **15**. In such a position, fluid (for example,

## 11

well fracturing fluid) passes through the bore of connector 301, mandrel 303, centralizer 503 and connector member 510, enters into ported member 401 (FIG. 6B), and passes out of port 511.

The casing at this location has (in some examples) been perforated, causing perforations 22 to communicate the interior of the well casing with oil and/or gas strata 13 (FIG. 1). Due to the nature of fracturing fluid, which usually contains solids (for example, sand), and pressure in the bore of slotted member 401, the fracturing fluid passes through perforations 22 (FIG. 6B) fracturing zone 13 (FIG. 1) and increasing the ability of oil and/or gas to flow from zone 13 into well casing 15.

Referring again to FIGS. 6A-6D, fracturing fluid substantially fills the annulus between member 401 and casing 15 (FIG. 6B); it then passes above and below slotted member 401. The fluid is stopped by packer element 404 (FIG. 6C) and cup packer element 308 (FIG. 6A) which is expanded to due the increase in pressure in the annulus between mandrel 303 and casing 15.

Upon completion of the well treatment, it is desirable to disengage expansion packer 404 and cup packer 308 from well casing 15. However, there is, in many instances, a pressure differential across expansion packer 404 (high pressure above expansion packer 404 and lower pressure below.) Pulling up on expansion packer 404 is difficult due to this pressure, creating a need to relieve the pressure differential. Pulling on cup packer element 308 is, in many instances, not possible; debris during the treatment operation collects above thimble 307. Therefore, the ability of the cup assembly to allow mandrel 303 to slide within cup sleeve carrier 309 without moving cup packer element 308 allows valve ports 421 to become unsealed and communicate with opening 421' with a very small movement of expansion packer guide 403 in a longitudinally vertical direction. During such motion, J-pin 13 (FIG. 4B) slides from position 473 again toward position 472, and port 421 and opening 421' are brought into communication (FIG. 7C). Pressure is therefore relieved above and below expansion packer element 404 and further vertical movement of mandrel 402 is therefore facilitated. As mandrel 402 continues to rise, guide 403 continues to decompress element 404 to a point where fluid flows between packer element 404 and well casing 15. Shoulder 430 of packer mandrel 402 engages cone 405 to lift cone 405.

At this point, J-pin 413 may be brought in alignment with position 471 (FIG. 4B) so that a downward motion can be applied to mandrel 303 (FIG. 7A and FIG. 3) in order to bring connector 301 in contact with cup retainer 306, thimble 307, and cup packer 308. Upon contact, cup packer 308 is forced downward in well casing 15, breaking up and loosening the debris that has been preventing vertical motion of cup packer element 308.

In some examples, an increase in pressure is applied to the region above cup packer 308 by pumping fluid from above and the annulus between mandrel 303 and well casing 15. In some instances, such an increase facilitates compression of cup packer element 308 from above to disengage cup packer 308 from well casing 15 and allow debris to flow past cup packer 308 into lower portions of well casing 15. In other examples, pumping is not conducted, and the solids and debris suspend slightly in well casing 15; such suspension then allows a vertical motion of mandrel 303 to cause cup packer element 308 to move up well casing 15. In further examples, cup packer 308 is lowered past perforations 22 where it is believed that the debris flows out of perforations 22 into the formation—facilitating a clearer casing 15—thus allowing for vertical motion of cup packer 308.

## 12

Referring again to FIGS. 5D, 6D, and 7D, attached to equalizing sleeve 416 is locator assembly 612, which is used to give an indication to the operator of when the locator passes a joint or collar in the casing; such locators and other means of locating position in casings are well known to those of skill in the art.

Referring now to FIG. 8A, expansion packer 404 is seen sealing casing 15 below an oil an/or gas containing strata 13a; cup packer element 308 seals casing 15 above an oil an/or gas containing strata 13a, which is in communication with the interior of casing 15 through perforations 22. Dashed arrows show the flow of well fracturing fluid through slot 511 and into strata 13a. After treatment of strata 13a, the packers are disengaged; and, as seen in FIG. 8B, they are repositioned to seal above and below an oil an/or gas containing strata 13b, which is then treated. In many well-bores, there are many different, vertically-spaced strata to be treated. Therefore, in many such situations, it is desired to treat the lowest most portion 13a, disengage packers 404 and 308, raise the assembly to straddle strata 13b, and then treat strata 13b. This process is continued from a lower portion of the well-bore to an upper region for as many oil and/or gas bearing strata as exist in the well-bore.

However, in some examples (see FIG. 9) there is communication between the first oil and/or gas bearing strata 13a and the second oil and/or gas bearing strata 13b; the fact or extent of the communication may or may not be known when treatment is conducted. In such circumstances, fluid (seen as dashed lines in FIG. 9) passes through slot 511, into strata 13a, up into strata 13b, and out of perforations 22 in strata 13b. This causes additional debris to be deposited over cup 308. If cup 308 cannot be disengaged, it is then difficult if not impossible to actually treat strata 13a without loss of the packer tool.

The sliding nature of cup packer element 308 allows recovery of the packer tool in many cases, and it also allows treatment of multiple strata 13 that are in communication with each other. In such a treatment, the straddle distance (between packers 308 and 404) is increased, as seen in FIG. 10. Use of a sliding cup carrier sleeve such as seen in FIG. 3 or any other longitudinally slideable cup 308 allows the straddle distance to be increased so that multiple zones can be treated in one treatment step. Spacer elements between the cup packer elements (which comprise, in many instances simple cylinders with bores) are used in some examples to.

In some treatment situations, a cup packer is unneeded. For example, after a well-bore has been formed and casing has been set, the casing needs to be perforated; and, in many cases, the strata 13 needs to be fractured. In many well-bores, there are multiple strata to be perforated and fractured, spaced along the well and separated by non oil and/or gas bearing strata. During treatment, it is desirable to isolate a previously-treated strata from the strata being treated, and so treatment is carried out from the lower-most strata to be treated first. An expansion packer is set below the strata being treated, thus isolating the lower portion of the well from the strata being treated. If the casing above the zone being treated has not been perforated, then there is no communication between the well and the strata above the strata being treated. Treatment of multiple strata are then accomplished, in at least one example, by a method comprising the steps of: fixing an expansion packer of a work string below a first strata; perforating the casing above the expansion packer; applying, between the work string and the cased well-bore, a stimulation fluid (e.g., fracturing fluid) through the perforations, equalizing the pressure above and below the expansion packer; fixing the expansion packer up at a second zone, the second zone being over

## 13

the first zone; perforating the casing above the expansion packer; applying, between the work string and the cased well-bore, a stimulation fluid through the perforations; equalizing the pressure above and below the expansion packer; and again raising the expansion packer. The application of the treatment fluid between the work string and the cased well-bore allows pressure measurements at the surface to more accurately represent the pressure at the perforations without having to account for the friction of fluid passing through the work string bore and through slots (e.g., 511) that would be used if the treatment fluid were passed through the work string.

In at least one example when a treatment process of perforation and treatment between the work string and the well casing is used, no cup packer is positioned in the well-bore, in order to allow the treatment fluid to flow between the work string and the casing. However, again in some examples, in place of the slotted member 401, a jetting tool (as is commonly known in the art), is used with a liquid and sand to perforate casing 15.

Other examples of the invention will occur to those of skill in the art without departing from the spirit and scope of the invention, which is intended to be defined solely by the claims below and their equivalents. Nothing in the previous portions of this document, the abstract, or the drawings, is intended as a limitation on the scope of the claims below.

The invention claimed is:

1. A system of treatment of a region in a well, the system comprising:  
 a first packer,  
 a first packer mandrel disposed radially inward of the first packer,  
 an expansion packer,  
 an expansion packer mandrel disposed radially inward of the expansion packer,  
 means for treating the region, wherein the means for treating the region is disposed between the first packer and the expansion packer,  
 means for moving the expansion packer, and  
 means for moving the first packer after the moving of the expansion packer; and  
 wherein the means for moving the first packer after the moving of the expansion packer comprises:  
 a first packer sleeve slideably mounted on the first packer mandrel,  
 a shoulder on the first packer mandrel, and  
 a shoulder on the first packer sleeve disposed to stop longitudinal movement of the shoulder on the first packer mandrel.

## 14

2. A system as in claim 1 wherein the means for moving of the expansion packer comprises means for longitudinally moving a mandrel with respect to the first packer.

3. A system as in claim 1, further comprising means for equalizing pressure above and below the expansion packer before the moving of the first packer.

4. A system as in claim 3, wherein the means for equalizing comprises a valve.

5. A system as in claim 4 wherein the valve is operated by movement of the packer mandrel and communicating the region with a portion of the well-bore below the expansion packer.

6. A system as in claim 4, wherein the valve comprises an opening below the expansion packer.

7. A system as in claim 1 wherein the first packer comprises a cup packer element.

8. A system for treating a well-bore on a work string, the system comprising:

an expansion packer mandrel for substantially rigid-connection to the work string,  
 means for setting a compressible expansion packer in a well-bore with a longitudinal motion of the work string,  
 means for treating the well,  
 means, below the expansion packer, for equalizing a pressure differential across the expansion packer,  
 means for raising the expansion packer; and  
 wherein the means for raising the expansion packer comprises a stop surface on the mandrel and a stop surface on the expansion packer, wherein the stop surfaces interact to cause the expansion packer to be raised during vertical motion of the expansion packer mandrel.

9. A system as in claim 8 wherein the means for setting the compressible expansion packer comprises at least one J-slot on the expansion packer mandrel interacting with at least one J-pin on a slip ring disposed about the expansion packer mandrel.

10. A system as in claim 8 wherein the means for treating the well comprises a substantially cylindrical member having slots therein.

11. A system as in claim 8 wherein the means for equalizing comprises a valve.

12. A system as in claim 11 wherein the valve comprises an opening below the expansion packer.

13. A system as in claim 11 wherein the valve is operated by movement of the packer mandrel and communicating across the expansion packer with a portion of the well-bore below the expansion packer.

\* \* \* \* \*